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THE ROLE OF IRP IN THE NATURAL GAS INDUSTRY : A CASE STUDY

by:

**Julius A. Wright, Principal Author, EDS
Larry Brockman, EDS
Patricia Herman, Barakat and Chamberlin, Inc.**

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Foreword

This report is the culmination of a project sponsored jointly by the Gas Business Unit of Niagara Mohawk Power Corporation and the United States Department of Energy. EDS Utilities Division, Energy Management Associates (EMA), was a subcontractor to the prime contractor, Martin Marietta Energy Systems Inc. The purpose of this project was to define, implement and institutionalize an Integrated Resource Planning (IRP) process for a natural gas utility. This report reviews the various steps in the development of the IRP, problems found in the process and the solution chosen by the project team.

When this project began, IRP for natural gas local distribution companies (LDCs) was in its infancy. Structural changes in the industry associated with shifts in market conditions and regulatory policy initiatives increased the challenges facing LDCs in managing their gas supply portfolio. LDCs responded by developing and implementing supply planning processes to cope with their new business environment by increasing staffing for the planning process and acquiring and developing analytical tools to perform economic evaluations of various supply options. They extended this planning process to incorporate LDC-sponsored demand programs. Thus competitive pressures, the desire to develop strategic plans that are consistent with maximizing end-use efficiency, national energy policy directives and state regulatory actions were the catalyst to changes in the natural gas planning process. One of these changes was the development of natural gas IRPs.

In the initial stages of gas IRP it was believed that LDCs, which possessed the expertise, experience and trust of customers, were well positioned to encourage the economic and efficient use of natural gas. These companies could use the IRP process as the vehicle to accomplish this mission. In regards to this project, it was considered essential that an LDC IRP process be proven practical so utility executives would not hesitate to move forward with natural gas IRPs.

This report reflects the authors' interpretation of NMGas' experience as the company attempted to incorporate the traditional features of integrated resource planning into its overall strategic planning process. At this time the New York State gas utilities are under no regulatory order to submit a formal integrated resource plan. In fact, based on NMGas' experience, and the changes taking place in the natural gas industry, it is quite possible that existing competitive

forces are sufficient to motivate regulated gas utilities to employ the principles of integrated resource planning.

As one as utility planner has stated "Competition adds a new dimension to the traditional integrated resource planning model. This dimension together with the unique market, operating, and system design characteristics of the natural gas industry will require a dynamic equilibrium planning model rather than a static unbalanced planning model. Social and private interests can no longer be mutually satisfied through monopoly pricing and cross-subsidization. Pressures to implement social policies through regulated utilities will have to be offset by opportunities that will enable cost recovery in the marketplace and not simply by regulatory approval. If this cannot be done, then such pressures should not be exerted" (Hamilton, William E., 1994).

We believe this project has been successful in examining the "practicality" of the gas IRP process and in defining areas where problems or issues arose and how Niagara Mohawk overcame these problems. The lessons learned and solutions found by Niagara Mohawk, while not applicable to all LDCs, can provide constructive guidance for implementing a gas IRP.

Larry Brockman
Patricia Herman
Julius A. Wright

Executive Summary

The natural gas industry has changed radically over the last decade. The Federal Energy Regulatory Commission's Order 636 completed plans to unbundle interstate pipeline services and create open access for distribution companies and their customers. There has also been increasing competition for local distribution companies (LDCs) from fuel oil, electricity and unregulated energy service companies. Meanwhile, the Energy Policy Act of 1992 includes provisions that encourage energy efficiency and promote reliance on competitive forces.

In response to these changes, coupled with growing environmental concerns and the need for increased energy efficiency, a number of state public utility commissions and LDCs took an interest in IRP for gas utilities. Gas IRP was in its formative stages and a variety of regulatory approaches were being considered when this project began. In response, this project originated with the total project scope being to define, implement and institutionalize an IRP process for the Gas Customer Service Business Unit of Niagara Mohawk Power Corporation (NMGas). *This report, the final product of this project, is intended to give insights on the methodology employed and the lessons learned in this process.*

WHAT IS AN IRP?

IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent planning assumptions to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost.¹

WHAT WERE NMGAS' MOST SIGNIFICANT LESSONS LEARNED ?

In discussions with company personnel several key issues kept rising to the top as significant lessons learned in this process. The issues embodied in these lessons should be the initial focus of any future IRP.

- **The objectives of the IRP should be consistent with corporate goals.**

¹See Primer On Gas Integrated Resource Planning , Goldman (1993).

- NMGas' strategic assessment went beyond the traditional supply/demand scope of IRP. A separate analysis was done for each of the functional areas below:
 - Transmission and distribution,
 - Gas supply and demand-side management,
 - Finance and rates,
 - Marketing and customer service,
 - Business planning and development.

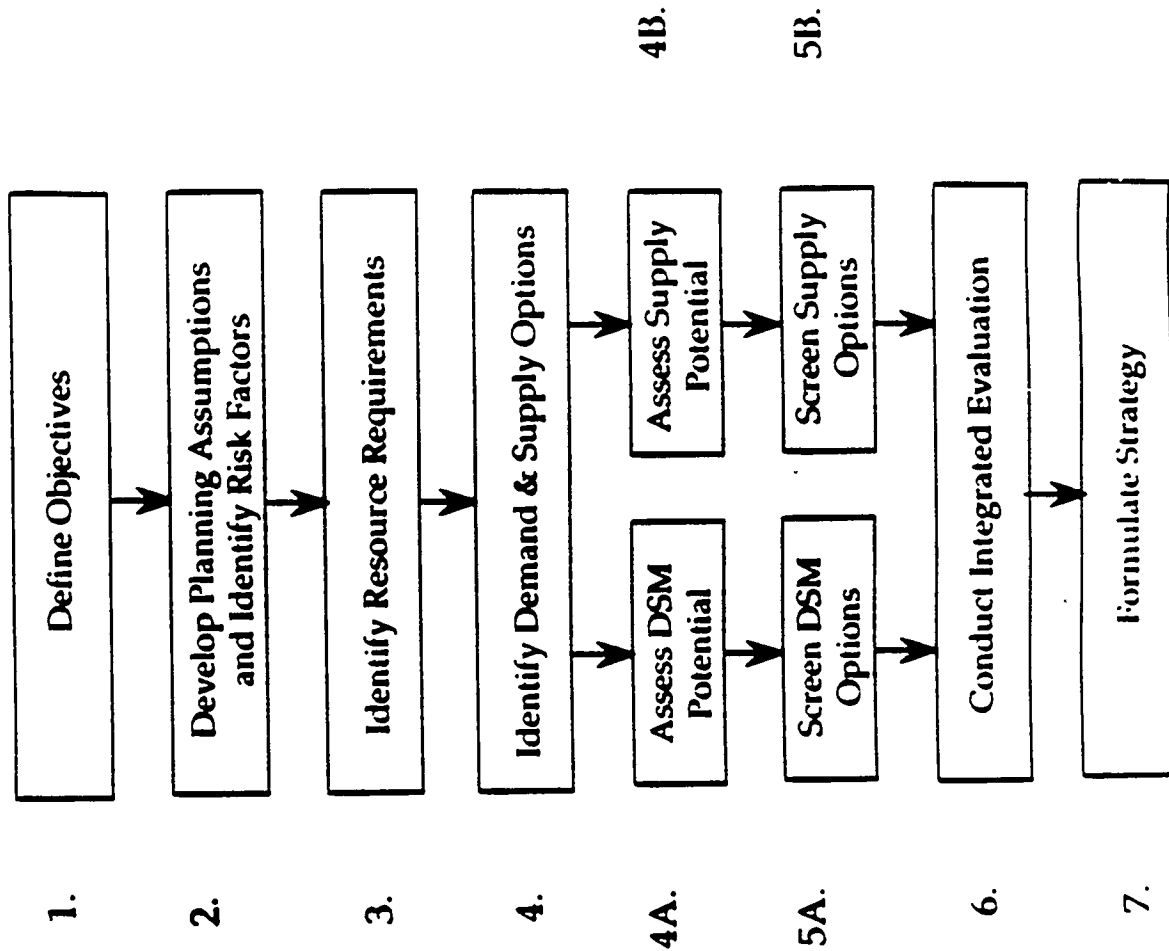
It is felt by NMGas that future IRPs, to be of value, should be incorporated into and be a part of the overall business planning process.

- There is great concern about the distribution of any final product and whether it becomes public. For example, the prospect of a competitor getting such a thorough "look" at NMGas and its future plans is a serious concern to management and could limit their response to future IRPs involvement.
- While those who worked on the project felt the IRP process should continue, as one project participant said "There remains to be specifically defined the bottom line benefits to the Company from the IRP process that are not captured in our traditional business planning activities. These need to be communicated to senior management in order to garner their support for continuing this activity."

AN APPROACH TO IRP

Initially, NMGas set out to follow the traditional seven step IRP framework shown in Figure E.1. However, as they proceeded they expanded the scope of their IRP well beyond what this framework suggests. For example, Figure E.1 suggests that in step four and five only supply- and demand-side options were considered. NMGas' draft IRP goes well beyond this and considers a

Figure E.1 Natural Gas Integrated Resource Planning Process



number of functional areas in their business. What led them to this expanded effort were the lessons learned as they proceeded down this seven step path.

The Lessons Learned In The First Step of The Process

- **The objectives of the IRP should be consistent with corporate goals.** *This was a critical decision for NMGas since it helped focus efforts towards common objectives.* NMGas' objectives indicated that the appropriate IRP economic evaluation criteria for NMGas at this time would be the Rate Impact Measure test.
- A multi-function project team was established to develop the IRP. This proved beneficial because the IRP process crosses a number of functional areas within the Company.
- There was a need for the team members as well as senior management to be "committed" to the project. Without this senior level commitment to the process and an appropriate priority status the project could be frequently delayed.

The Lessons Learned In The Second Step of The Process

- **Careful attention to the planning assumptions and policy guidelines is essential.** *These planning assumptions were critical decisions for NMGas since they define the study parameters and guidelines.*
- Planning assumptions are subject to revisions. This is due to the changing nature of the gas industry and related competitive pressures.
- Planning assumptions and policy guidelines must be tailored to the requirements of the gas industry and to each company's strategic objectives. Each LDC will have assumptions related to their specific needs, goals and service areas that must be considered in any planning scenario used to develop the IRP.

The Lessons Learned In The Third Step of The Process

- **The major conclusion of this step indicated that NMGas would have sufficient supply resources and related transmission capacity beyond that necessary to meet projected firm demand.** *This was a critical conclusion that affects how a company's IRP proceeds.* For example, as opposed to a load reducing demand-side program being used as a substitute for projected new supply resources, those demand-side programs are now being considered as "replacement" energy for supply resources already committed.
- **It was necessary to establish criteria related to resource options.** *These were critical decisions because they focused NMGas' search on resources that met the Company's predefined criteria for comparability of service and reliability.*
- Gas resource planning is likely to focus on multiple demands. This can include peak day, peak season, etc.
- Gas utility planning criteria for individual gas utilities may differ more than planning criteria for electric utilities. For example, there is likely to be more disparity in reserve margins among gas utilities.
- A theoretically sound avoided cost methodology was defined for gas utilities that can be used in the economic evaluations of resource options.

The Lessons Learned In The Fourth Step of The Process

- **Make sure the economic screening criteria matches the goals of the IRP.** *It is critical to coordinate the objectives of the company with the objectives of the IRP and subsequently the economic screening criteria.* To eliminate needless efforts the appropriate objectives need to be established early in the process.
- Start with a load shape screening process in Step 4. The screening effort performed in this step could have been shortened and focused by beginning with a simple load shape screening analysis.

Lessons Learned In The Fifth Step of The Process

- Coordinate the work between Steps 4 and 5. These two steps are by nature highly interrelated, and therefore, it is recommended that they be completed by the same team of people.

The Lessons Learned In The Seventh Step of The Process

- There was difficulty in finding available time for the resources required to complete the task. *This is a critical decision that NMGas had to address and is primarily a resource allocation issue.*
- Once resources were committed the process took approximately 10-12 months of actual time to complete.

OTHER INSIGHTS AND LESSONS LEARNED BY NMGAS

In an effort to add additional perspective to this review a number of individual interviews were conducted with Company personnel who were involved in the project. They were asked about their perception of the pitfalls, problems and benefits associated with the process. The following is a summary of their major observations.

- There was consensus among the team members that the process was worthwhile and should continue. A majority felt that regular updates would be appropriate and a general review of the whole IRP might be appropriate every two to three years.
- The process from start to finish on this initial IRP took a total time commitment of 10-12 months. It is believed that future IRPs will benefit from this experience and the time could be cut to four to six months.
- Consideration should be given as to how extensive future avoided cost evaluations need to be. While an avoided cost methodology was developed, on initial analysis it might prove simple and effective to review options based on a simple gas price projection.

Chapter 1

Introduction

The natural gas industry has changed radically over the last decade. The Federal Regulatory Commission's (FERC) Order 636¹ completed plans to unbundle interstate pipeline services and create open access for distribution companies and their customers. While 636 created some competitive threats, it also created opportunities for growth. The industry challenge is to meet the threats of Order 636 while taking advantage of the opportunities it presents. In addition there has been increasing competition for gas supplies, competition from fuel oil, electricity, other gas companies and unregulated energy service companies.

More importantly, natural gas is being looked upon to play an increasing role in the growing energy demand of the United States. It provides an abundant source of energy within our country's borders, and is one of the most economical fuels for producing energy in an environmentally benign manner. In response to this growing need for energy as well as utilities and regulator's continuing development of Gas Integrated Resource Plans, Oak Ridge National Laboratory issued a Request for a Proposal, on May 25, 1991, related to a number of IRP issues including the implementation, methodology and problems associated with the development of a gas IRP.

Contemporaneously, the Energy Policy Act of 1992 (EPACT)² included various provisions that encouraged energy efficiency and promoted reliance on competitive forces. EPACT amended the Public Utility Regulatory Policies Act (PURPA) of 1978 by adding two new standards for consideration by state PUCs: (1) use of integrated resource planning by gas local distribution companies (LDCs), and (2) encouragement of investments in energy efficiency and load-shifting measures by ensuring that these investments were at least as profitable (taking into account the income lost from reduced sales under such programs) as prudent supply-side investments. State commissions were required to provide public notice, conduct a hearing on the appropriateness of these new standards, and make a determination about whether or not to adopt each standard by

¹See Goldman et al, (1993), NMGas (1994), and Gaske (1993) for a discussion on FERC Order No. 636.

²See NRRI (1993) for a discussion of the effects of EPACT on LDCs.

October 23, 1994. In 1993 the New York State Public Service Commission initiated a proceeding on Gas IRP in response to these 1992 Energy Policy Act mandates.

These developments in gas wellhead markets and changes in regulatory policy at the Federal Energy Regulatory Commission (FERC) created new challenges and opportunities for gas LDCs and their state regulators. State regulators, who oversee a distribution segment that still has features of a natural monopoly, have to respond to and manage the competitive forces that resulted from gas industry restructuring. Increased reliance on market forces does not necessarily mean that state regulation is outmoded, but rather that flexibility and forward-looking planning processes become increasingly important as the number and type of utility supply choices increase.

Furthermore, a number of state public utility commissions (PUCs) have taken an interest in Integrated Resource Planning (IRP) for gas utilities. IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent short-term and long-term energy service needs at the lowest total cost.³ Gas IRP was in its formative stages and a variety of regulatory approaches were being considered and tested by state PUCs. However, a survey of regulatory staff conducted for the National Association of Regulatory Utility Commissioners (NARUC) revealed that limited information and lack of consensus on various IRP-related technical and policy issues has hindered progress.⁴ NARUC concluded that additional analysis of selected issues would be useful, particularly if it drew on the initial experiences of PUCs and gas utilities that implemented gas IRP.

This project was developed in response to the need for more information about gas IRPs and the Oak Ridge RFP, . The purpose of this project was to define, implement and institutionalize an IRP process for an LDC, the natural gas subsidiary of Niagara Mohawk Power Corporation (NMGas). The project goals were to produce an integrated resource plan that defined strategies for NMGas, establish planning procedures that could be the basis of future planning activities

³ Goldman, et al (1993), Etter (1992).

⁴Goldman and Hopkins (1991).

by the Company, and develop and demonstrate the practicality of analytical techniques that could be used in natural gas integrated planning evaluations.

This report, the final product of this effort is intended to describe the process of developing NMGas' IRP. In this task, this manuscript does not attempt to develop the IRP itself but rather give insights on the methodology employed and the lessons learned.

Chapter 2 discusses what an IRP is and how it relates to other planning functions in the company. In Chapter 3 NMGas' approach in developing its IRP is outlined. Generally speaking, their approach was similar to the standard gas IRP practice as it was later developed in the NARUC Gas IRP Primer.⁵

The fourth through the tenth chapters actually discuss the steps taken in developing their IRP. The first step, addressed in Chapter 4, was defining corporate objectives to ensure that resource plans developed within the IRP were consistent with these overall strategic goals. Chapter 5 deals with the development of planning assumptions and criteria. For example, the time period for which to conduct any planning or resource evaluations has to be specified. In Chapter 6, the identification of current resources and resource requirements is considered. This effectively defines the current status or base case scenario for the Company. As part of this phase, a determination of the Company's avoided cost was performed using the current supply/demand relationships that were developed in this step. These avoided costs are then used in subsequent steps as an evaluation criteria for optional resources.

Chapters 7 and 8 discuss the identification and screening of resource options. In this phase, resources are screened and those identified as cost effective and consistent with the Company's strategic goals are passed along as potential resource options to be considered in the next step in the process, the integration of the resources into a proposed optimal IRP. This integration step is the subject of Chapter 9. Once this integrated plan is specified, the final step, discussed in Chapter 10, is developing and IRP implementation strategy and report.

This manuscript closes with a discussion summarizing the problem areas and insights gained by NMGas as they went through this process.

⁵See Goldman, et al (1993).

Chapter 2

GAS INTEGRATED RESOURCE PLANNING : THE TRADITIONAL APPROACH

2.0 Overview

A confluence of high costs for new production plants, concern for the environment, and continued escalation of fuel prices forced electric utilities to begin performing Integrated Resource Planning (IRP) in the 1970s. Gas utilities, however, did not face the same problems as the electric's such as the large cost overruns related to nuclear generating plants, so regulators and gas utility planners saw less need for gas utilities to engage in IRP. Eventually, however, many gas utilities were ordered to create their own IRP process. It was natural, at that time, to look at the traditional approach of electric utilities to see what was applicable to gas utilities and what was not.

This chapter summarizes the IRP approach as it was envisioned for gas utilities. More detailed treatments of this traditional IRP approach can be found in Goldman, et al (1993) and Etter (1992). It is not our intent to duplicate these sources here. Rather, we attempt to give the reader a background to the IRP approach that evolved at NMGas and where applicable define how it may be different from the more traditional approach.

This Chapter is structured in the following manner. In the next section a definition of IRP is offered which is followed by a brief historical perspective of how IRPs have developed. Section 2.3 discusses the difference between gas and electric IRPs. This Chapter closes with a section describing the relationship between an IRP and strategic planning.

2.1 What Is An IRP?⁶

Integrated resource planning (IRP) as practiced today is the continuous process of identifying and evaluating combinations of demand-side and supply-side

⁶Sections 2.1, 2.2, and 2.4 of this chapter draw heavily upon John H. Chamberlin in Enholm (1994).

resources that will achieve specified objectives and meet forecasted demand. Through this planning process, the utility and other participants seek to find the least-cost manner in which loads can be met, or modified, while meeting constraints such as maintaining a given level of reliability and customer service.

While IRP from a regulatory oversight perspective is fairly new for gas utilities, it has been applied extensively by electric utilities over the last decade. Today, IRP is the principal means electric utilities use to identify new resources. It has also become a key vehicle for state regulatory commissions and intervenors to understand and influence the planning process.

Before IRP, traditional utility planning was simply resource planning. The utility's forecast of expected customer load growth was taken as a given, and the planning methodology consisted largely of matching new generation capacity or energy purchases to that load growth.

During the 1970s and early 1980s the costs associated with traditional resource planning for electric utilities rose due to a combination of factors. Interest and inflation rates rose dramatically (inflation reached a high of 17.8 percent in 1980). Fuel prices sky rocketed due to the OPEC embargo (1973-74) and the Iranian revolution (1979).⁷ The 1970s also marked the beginning of the environmental movement, which resulted in legislation that increased the cost and time for plant construction. And finally, despite dramatic economic changes and the new environmental awareness, utilities continued to project the same high growth in demand they had experienced for the last three decades. As a result many large baseload plants, including many nuclear units, were approved, budgeted, and begun that were later found unnecessary.

In order to mitigate cost increases and respond to the environmental movement, regulators, utilities and others became interested in expanding their planning methodologies to include a wider diversification of resources. In 1978 the Public Utilities Regulatory Policy Act (PURPA) forced the consideration of cogeneration and renewable energy resources⁸ and planners began to consider opportunities

⁷See Goldman, et al (1993).

⁸See Plummer and Troupman, (1990).

to modify customers' use of electrical energy. Planners no longer took the level and timing of customer demand as a given, but as a variable that could be modified by demand-side management (DSM) programs. Thus, "integrated" resource planning for electric utilities came into being as both demand- and supply-side resources were combined into one resource plan. For gas utilities the evolution to IRP was in large part a response to similar environmental concerns, the preservation of scarce resources and the growing national interest in overall energy efficiency.

2.2 What IRP Has Offered and How It Has Evolved

Over the past 10 years IRP has helped electric utilities to think about how to expand their service offerings, to improve the quality of the plans adopted and to minimize confrontations with ratepayers, environmental advocates and others through a collaborative process.⁹

The process has evolved from a linear process -- with DSM being added almost as an afterthought -- to one that recognizes the dynamic interrelationships between demand-side and supply-side options, and between resource plans, rates and sales. It has also increased in complexity because of public scrutiny, intervention and legislation caused by the increasing strategic importance of energy to the national economy; wider availability of energy efficient technologies; greater choices of fuel suppliers; and growing environmental consciousness.

The IRP process is now under pressure, however, from deregulation and competition, technological change (microwave heating and drying, ultraviolet curing, membrane separation, gas air conditioning and other recent electro- and gas technologies), and economic change (e.g., trade agreements, global competitive pressures).¹⁰

⁹See Broehl (1984), Cavanagh (1986), Chamberlin (1987), Nader (1992), and Kreith (1993).

¹⁰See Black and Pierce (1993), Rudden and Hornich (1994), and York (1993) for a thorough discussion of these changes and their affect on IRP.

IRP came into prominence rapidly. In less than a decade it became the leading edge planning tool for utilities and commissions that wanted lower costs, more efficiency and environmental improvement. Many now worry that it is just as quickly becoming obsolete. Three forces are driving this trend. First, increasingly sophisticated public participation at first had an informative, creative, and constructive effect leading to better planning and more options. Now, however, it threatens to stymie the planning process by complicating and prolonging the process so that before the plan is agreed upon, the utility has already by necessity made the day-to-day decisions that now make portions of the plan irrelevant.

Second, commissions and other parties to IRP want to expand the scope of the process. These expansions include increased sophistication in accounting for the interactive effects of rates and sales, DSM and avoided costs, and the monetization of external environmental costs. Where such expansion has been tried, the process has been cumbersome and as well as computationally and organizationally difficult. One eastern utility, for example, now needs six to seven months to do the required calculations for a plan that must be filed annually.

Thirdly, IRP has two critical conceptual weaknesses with regard to competition. First, it focuses on cost minimization as the only goal of the planning process. And second, it assumes that customer loads are predictable and that customers in a particular area will be served only by the "host" utility. Competition undermines both the assumption that lowest cost is equivalent to greatest value and the expectation that customers are made dependent, and therefore relatively predictable, by the fact of geography.

2.3 Differences In Gas and Electric IRP's¹¹

While electric IRPs provide a basic guideline for the development of a gas IRP, the two differ in several important aspects. For example, an electric utility must make decisions regarding procurement of primary forms of energy (e.g., nuclear,

¹¹See Lerner (1992).

coal, natural gas) which are then to be converted into its energy product (kWhs). This naturally leads to decisions regarding the construction and operation of electric generating facilities. There are also decisions regarding siting of electric generating facilities, transmission and distribution of electricity, and providing customers service. Natural gas utilities, on the other hand, perform a smaller set of functions. More specifically, there is no analogy in the gas industry to an electric generating unit.

In effect, the different scope of planning functions carried out by natural gas utilities results in major differences in both the cost structure and cost per unit of delivered energy. For example, natural gas utilities' purchase gas costs are usually around 60 percent of their total cost, while for electric utilities' fuel costs are about 33 percent of their total cost. On the other hand, facilities costs for electrics generally run about twice as high as those for gas utilities. In short, electric utilities are more oriented towards facility planning than gas utilities and are therefore more capital intensive.

Also, the planning horizon for electrics is usually much longer than gas utilities. The reason is related to the requirements of electric generating facility long lead time planning requirement and also a function of the more competitive, shorter term gas purchasing strategies.

Finally, there are major differences between the screening and optimization of the supply side for gas and electrics. For electrics, the choices involve both technology and fuel type. For gas utilities, the choices are primarily between the many sources of purchase, transport and storage.

2.4 IRPs Link to Strategic Planning

As the IRP process has grown and evolved, it has become dangerously close to being regarded by some as synonymous with strategic planning—that is, as the vehicle by which the key market decisions of a company are determined. However, as the energy service market becomes increasingly competitive, the IRP process as we now know it can lead to increasingly non strategic results.

Thus, a conflict is growing and could ultimately lead to the demise of the IRP process as it is employed today.

It may be that "IRP" remains the term of choice as utilities move into strategic planning. However, the current IRP process and true strategic planning differ in at least three ways.

First, while an IRP tries to identify the least-cost way to meet forecasted energy service needs, which are assumed captive to the utility, utilities will use strategic planning process to develop and test strategies for acquiring and maintaining market share.

Second, under current IRP constructs, a utility adds resources, either supply- or demand-side, when its forecast indicates that reliability will fall below accepted levels. Under strategic planning, resource additions will become market-driven: A utility will commit to a new resource only when it is confident that there is a market ready to buy the "output" (which may be therms, kilowatt-hours, or energy savings) at a price sufficient to cover costs.

And third, the IRP process often encourages or requires a level of public participation. It is unlikely, however, that the same level of public exposure and involvement would be tenable under competition. A utility that is striving to remain competitive cannot plan market-share strategy in full view of competitors. Thus, while strategic planning is closely tied to an IRP's development, the two perform different functions in a company's planning process.

Chapter 3

An Approach To Gas IRP

3.0 Overview

This chapter gives a general review of the approach NMGas took in developing its IRP. In effect, they followed a procedure similar to the steps that were later published in the NARUC Gas IRP Primer. In outlining the process this chapter is arranged as follows. In the next section the basic organizational steps followed throughout the project are discussed. Section 3.2 defines several specific issues that project coordinators targeted as important issues to resolve, in particular the methodology used to determine avoided cost which is used to evaluate the economics of competing resources. The closing section provides the proposed project calendar.

3.1 Organizational Approach

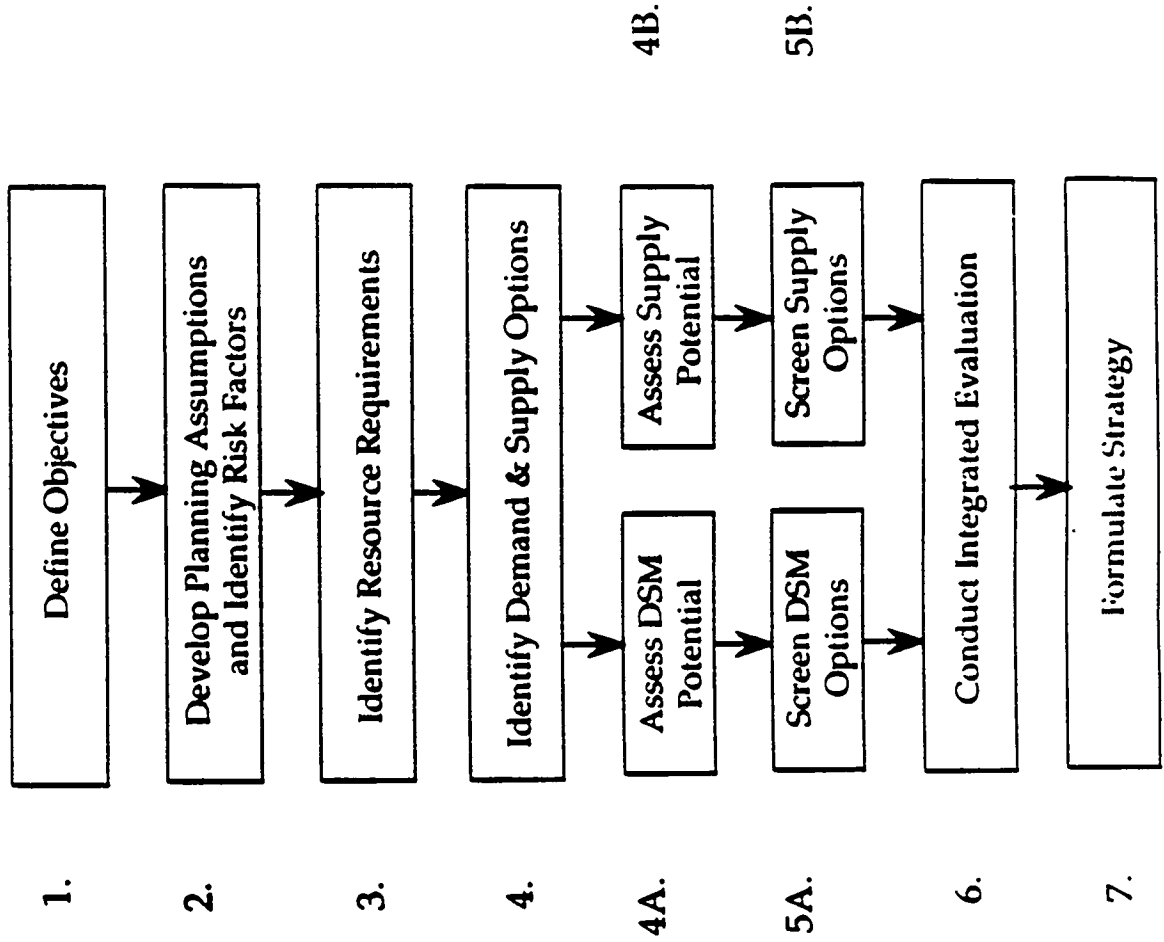
NMGas' IRP approach utilized for this project began with the basic IRP planning framework utilized by electric utilities¹². That framework was adapted as necessary to reflect specific characteristics that differentiate the supply and demand situation of LDCs from that of electric utilities. Figure 3.1 presents a simple schematic of the IRP process that was utilized in the project. Each of the seven steps shown in Figure 3.1 are discussed below.

Step 1 : Objectives and Evaluation Criteria

The starting point of the process is the identification of corporate objectives and developing an understanding of the implications of those objectives for the plan. This first step is very important because the IRP should be developed in a manner that focuses on resources consistent with the overall objectives of the company. For example, it is important to

¹²This general framework is consistent with the methodology eventually adopted in the NARUC Gas IRP Primer.

Figure 3.1 Natural Gas Integrated Resource Planning Process



establish a set of evaluation (measurement) criteria in order to judge how well various plans meet the objectives. However, it should be recognized that the objectives of the company and those of regulators are probably different to some extent. This reality must be considered by any utility in weighing its overall goals and the evaluation criteria it chooses. Furthermore, each utility will have objectives that are unique to it. Given these qualifications, Table 3.1 lists some of the more common IRP objectives and their key measurement or evaluation criteria. Note that the key measurement criteria may be listed as the "Total Resource test" or the "Utility Cost test", etc. These are the generally accepted economic evaluation criteria applied to demand-side programs. These tests are further defined in this section under "Demand-Side Screening."

Step 2 : Planning Assumptions

This step's focus is to develop planning assumptions. These assumptions would be developed in conjunction with a comprehensive analysis of the business environment. This analysis would examine and evaluate the underlying factors that will influence the future environment. These factors would include regulatory policies, the dynamics affecting future customer requirements and the dynamics affecting future gas supply. The result of Step 2 would be projections of the components necessary to develop forecasts of customers requirements and of the costs of supply sources.

In addition, this analysis would identify the key risk factors that could cause future supply and demand conditions to be significantly different from the forecasts. This risk analysis will be utilized to define alternative scenarios to judge the robustness of resource portfolios across a range of potential future outcomes. Thus, the result of Step 2 will be projection for the inputs into the planning process and identification of risk factors that would affect those inputs.

One essential aspect of the planning assumptions was a good base of knowledge of the economic and technical potential for demand side

**Table 3.1
The Range of Objectives in Gas IRP**

Major Stakeholder	Objectives	Key Measurement Criteria
PUC  Utility	Minimize source energy requirements	Total energy consumed
	Minimize total social costs	Societal Cost test, quantities of pollutants released
	Minimize total customer costs	Total Resource Cost test
	Share benefits equitably	Rate or bill impacts by customer class
	Minimize customer bills	Utility Cost test
	Minimize rates	Ratepayer Impact Measure test
	Maintain reliability	Expected curtailments, reserve margins
	Maximize planning flexibility	Lead time of selected resources, dollar magnitude of long-term commitments
	Maintain market share	Market share, relative size of marketing budget
	Maximize shareholder value	Stock price, return on equity

measures among the end-user customer base served by NMGas. This project drew upon the results of a work effort sponsored by the New York Gas Group, (a confederation of gas LDCs in New York State), and the New York State Energy Research Development Authority. This effort was conducted by the American Council for an Energy Efficient Economy to review gas DSM potential. NMGas had access to this research for the development of an IRP. The knowledge gained of how customers in the NMGas territory respond to energy and DSM marketing initiatives was also a key input to this project.

Step 3 : Identify Resource Requirements

In this step the resource requirements were determined by comparing committed supply capability to forecasted customer requirements. This comparison was made using EMA's gas planning system, SENDOUT, to simulate NMGas' operations over the planning horizon. The supply resources and demand (or load) forecast effect the entire expansion of the utility. The formalization of the IRP process has focused more light on this process. In addition, the art and science of forecasting has advanced in recent decades. There are three basic techniques used in load forecasting:

1. Trending
2. Econometrics
3. End Use

Econometrics and End Use have overtaken Trending in recent decades. End Use has more direct application in demand-side management. In addition, the focus on integration has created a new emphasis on ensuring that the assumptions used to create the demand forecast are consistent with the assumptions used in the supply- and demand-side evaluations. An objective of minimizing risk and ensuring flexibility to changing conditions has created the need to look at more than one forecast. It is common to see at least high, medium, and low demand forecasts. In many cases there are even demand forecasts for each scenario examined in

the risk assessment stages. Competition and deregulation in the industry have made this even more critical.

A second phase of this step is identifying the "base case" supply resource requirements. This will identify any shortcomings in the firm's current supply plans and supply resources. At this stage, avoided costs are determined that can be used in later steps for screening energy resource options. Long run avoided costs are estimated based on the existing supply/demand plan. These avoided costs are used in subsequent steps as a common denominator price signal to measure the cost impact of small changes in the overall system supply/demand situation.

An appropriate avoided cost methodology was felt to be a critical component of any IRP process. A report by Lawrence Berkeley Laboratory (LBL) cited the absence of an avoided cost methodology as a major obstacle to successful gas IRP. This project utilized an avoided cost methodology that: reflected the supply planning process and principles used by NMGas; used the specific supply options projected to be available to the company; and incorporated the key supply and demand characteristics that differentiate LDCs from electric utilities. (Appendix I discusses in detail the exact methodology to use in determining the avoided cost.)

Step 4 : Identify Demand and Supply Options

At this point in the plan's development a list of potential resources is defined. On the supply-side, the options include firm and interruptible transportation capacity, various supply contracts and suppliers, potential storage and optional peaking supplies such as LNG, propane, and interruptible service. For each of these options the LDC will need to determine prices, both current and projected, reliability, availability, timing and risks. In the same fashion a list of potential demand-side programs needs to be established. These can include peak reduction programs, heating season load reduction programs, higher efficiency equipment, selective load building, various rate design options and a variety of fuel switching programs. As with the supply-side options, for each of these demand-side options information must be defined such as

the implementation costs, market penetration, lost revenues, energy savings, risks and other program information.

Step 5 : Resource Screening

In Step 5, the preliminary economic evaluations of resource options is undertaken. This step utilized parallel efforts which examined separately supply and demand options. Parallel efforts were utilized because of the specialized skills and knowledge required for each activity. The linchpin coordinating these activities is the long run avoided costs (LRACs) developed in Step 3. For example, LRACs would be used to measure the system costs that would not be incurred due to energy efficiency programs and to measure additional system costs that would be incurred to marketing activities. Consequently, the task of this step is essentially a screening process for demand-side and supply-side options, discussed below, that develops lists of resources that are technically and economically feasible.

Demand-Side Screening

The "integrated" part of the IRP name came from the desire to create so called "least cost" plans by integrating supply-side options with low cost demand- side options. However, there are hundreds of demand side management options available and it is not usually possible, nor advisable, to try to look at all possible combinations of these alternatives. Instead, it is necessary to create screening methods to weed out the alternatives that do not merit further consideration.

Screening methods have been developed by electric utilities that attempt to look at all the attributes important to the objectives of the process. In reality, the most developed screening tools look primarily at costs. In this regard, most utilities screen demand side management alternatives using some form of the four cost/benefit tests developed in the California Standard Practice Manual.¹³ These four tests look at the demand side programs from the following viewpoints:¹⁴

¹³See "Economic Analysis of Demand-Side Management Programs" (1987).

- Societal or Total Resource Test - the cost effectiveness of the program from society's viewpoint, or the viewpoint of all ratepayers.
- Participant's Test - the cost effectiveness from the viewpoint of customers participating in the DSM measure.
- Non Participant's Test - the cost effectiveness from the viewpoint of customers who don't participate in the DSM measure -- i.e., the impact on rates.
- Utility Test - the cost effectiveness from the viewpoint of revenue requirements.

Supply-Side Screening

There are as many screening alternatives available on the supply-side as the demand-side, which makes it necessary to adopt a manageable set of techniques for screening supply-side alternatives. This is usually done using some measure of cost, but the method should look at the effects on the other objectives as well. Many techniques for supply-side cost minimization have been developed. Some of the more common techniques are listed below in increasing order of complexity.

- Screening Curves
- Linear Programming
- Bender's Decomposition
- Dynamic Programming

Many of these techniques use computer software to help perform the supply side screening valuation. In fact, many are also used in the integration of supply and demand side options.

¹⁴There is ongoing debate as to whether these tests are true measures of the cost/benefits they purport to be. In fact, while NMGas applied these tests in the COMPASS DSM evaluation model, they recognize the limitations of each in trying to capture the appropriate costs and benefits.

Step 6 : Integration and Evaluation

The goal of resource integration, and indeed the whole IRP process, is to find the mix of resources that best meets the predefined objectives of the company. After the numerous demand-side and supply-side alternatives have been screened to a manageable set of alternatives, the integration process is undertaken. The plan or plans defined by this process are then evaluated for how well they meet the initial objectives set out at the beginning of the planning process. This resource integration is facilitated by the use of gas dispatch and capacity expansion models. These models compute total system cost and help insure that present and projected energy service needs are met.

One potential problem in this integration process are cases where the company objectives and measurement criteria are not complementary. For example, a plan that is reliable or creates the least environmental damage may not be the one with the lowest cost. In addition, the plan with the lowest rates may not be the one with the lowest present value of revenue requirements. The integration process is therefore a multi-variable and often a multi-step optimization process.

As a point of reference, electric utilities have devised a range of methods for trying to accomplish this integration. The more common approaches include:

- Least cost supply/demand plan with judgment on other attributes
- Least cost supply/demand plan with monetization of other attributes
- Weighting and ranking schemes

The most common form of integration for electric utilities is the creation of a least cost supply and demand plan, subject to certain other constraints, such as reliability, with judgment applied to the other attributes. These methods can be extended by monetizing some of the other attributes and then creating a least cost plan. Several electric utilities, including Niagara Mohawk Power Company, have created weighting and ranking schemes that attempt to create plans that best satisfy multiple objectives. Similar methods can be employed for gas IRPs

Step 7 : Develop IRP Document and Strategy

The final step in the process is to develop an implementation strategy and formalize the IRP in the form of a document, which is often filed with regulatory authorities. This document should address each of the steps in the process, the final resource mix chosen, and could also define a proposed implementation plan and schedule. To a large extent this final IRP document reflects the proposed business plan for the company over the next three to ten years.

3.2 Specific Issues to Be Examined

The implementation of this IRP framework required that important issues be examined in order to provide useful lessons for other utilities seeking to implement an IRP process.

The first major issue considered data requirements. IRP necessitates that LDCs develop and implement a variety of activities to increase the quality of the data available to conduct planning studies. This problem is most acute on demand issues where LDCs have minimal data to evaluate the impact of specific energy efficiency programs or marketing strategies. This project identified data requirements for a gas IRP, established initial programs to acquire such data, and initiated appropriate methodologies to utilize the data in planning evaluations.

A second major issue addressed the development and utilization of the Company's avoided costs. This project demonstrated a theoretically sound method for defining gas avoided cost which could be used as a practical tool for evaluating changes to the supply/demand balance brought about by energy efficiency or marketing programs. The approach was planning-based, using the same principles, analytical tools, methods and decision framework utilized by the LDC for supply planning. The starting point of the methodology is supply and demand forecast that reflect reasonably anticipated plans regarding supply options and demand activities and that satisfies the LDC's reliability planning standards. The core question which the avoided cost methodology seeks to answer is how would the supply plans and gas dispatch change in response to changes in demand on various days. The answer to this question will depend

upon the service priority of the demand that changes (e.g., firm or interruptible) and the time period during which demand changes (e.g., design day or winter season). The avoided cost methodology was demonstrated to be flexible and able to reflect differences among LDCs.

3.2 Project Calendar

The initial project calendar established the following dates:

Step 1:	Define Objectives	February, 1993
Step 2:	Develop Planning Assumptions	March, 1993
Step 3:	Identify Resource Requirements	April, 1993
Step 4:	Identify Supply & Demand Options	May, 1993
Step 5:	Screen Options	June, 1993
Step 6:	Conduct Integrated Evaluation	August, 1993
Step 7:	Develop Gas IRP	October, 1993

Note that this was the original project calendar which covered a total of nine months. As the project proceeded, these dates slipped due to resources with higher priorities, such as a rate case. However, in total, according to Company personnel, once the project was staffed and prioritized it took 10-12 months to produce the initial IRP.

Chapter 4

Step 1: Defining Corporate Objectives

4.0 Overview

The objective of this step was to identify corporate objectives and develop an understanding of how the IRP process furthered these objectives. Intrinsic in this procedure is the development of IRP guidelines consistent with the corporate strategic plan. To facilitate this process, a project team was put together, which included members from all NMGas' functional areas that were expected to be affected by the IRP. This group's charge was essentially to produce the final IRP and accompanying documentation. In this Chapter, the initial organizational issues associated with establishing this project team, defining its purpose, defining the IRPs purpose and defining the corporate goals are discussed.

This Chapter is organized in the following manner. In the next section there is a discussion of the initial efforts of the project team in establishing their charter. Section 4.2 describes the initial guidelines established by the team in regards to corporate goals, a definition of IRP for NMGas, and IRP objectives. This section is followed by a discussion of regulatory issues related specifically to the Company's IRP process and a section that considers rate design issues related to the IRP. This chapter closes with a summary of conclusions that could be drawn from the process of developing this first step in NMGas' IRP.

4.1 Developing a Corporate IRP Focus

To guide the IRP process a project team or IRP Committee was formed from members representing departments thought to be affected by an IRP. These included supply planning, marketing, facilities development, rates and finance. While this would appear to be a simple task, internal memos proved this was not the case. Five department managers were asked to comment on the IRP concept and provide a team member. Their responses included the following comments:

- strongly oppose staff involvement and collaborative process

- company is too departmentalized for this type of joint planning
- how useful is IRP planning if everything changes every month or year
- control planning is necessary
- this process should not administratively burden the growth movement
- IRP should address concerns of senior management
- need a group that integrates everything
- concerned about timing, [I] don't want to be slowed down
- concerned about state regulation
- how to reconcile need to act now and need to plan
- want to reserve right to steer from plan

As can be seen from these comments, there were a number of concerns about the IRP process, the time involvement and even whether a joint planning effort was workable. Regardless, the project team was organized, and the IRP planning process began.

One of the first tasks undertaken by the Project Team was defining how the IRP process fit into the corporate objectives at NMGas. Initially, there were three issues that management groups affected by the IRP process had to address and build a consensus on which were:

1. What are the corporate (NMGas) goals and objectives that IRP is seeking to meet ?
2. What does the IRP mean for each company group -- i.e., what are the IRP expectations for supply planning, marketing, rates, etc.?
3. What is the best organizational structure for accomplishing an IRP at Niagara Mohawk Gas ?

The project team's first task was to develop answers for these three issues. This proved to be difficult. Indeed, this phase of the project, initially scheduled to be

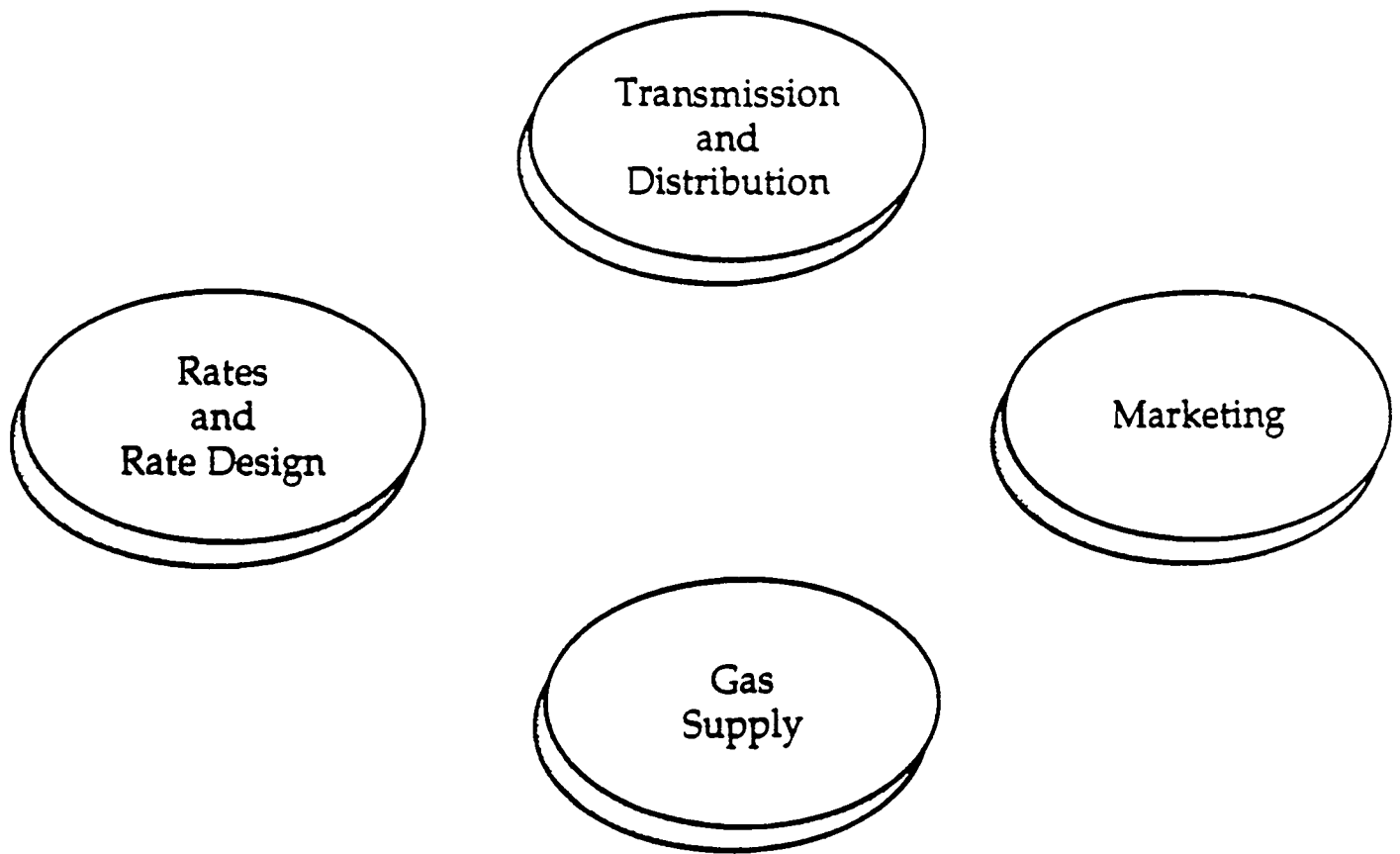
completed in the project's first month, actually began in the fourth quarter of 1992 and was operationally complete by February of 1993. The reasons for this activity taking longer than imagined were:

- The IRP process affects literally every phase of a gas LDC's supply planning efforts. Figure 4.1 shows the numerous activities involved in the LDC supply planning. Management in each of these areas must be "in sync" with whatever IRP goals, methods and objectives are developed. However, reaching a consensus among the numerous corporate business units, and thus, getting that help in developing the IRP, proved to be a challenge.
- In developing an IRP, the process must have goals consistent with the corporations'. However, each goal is subject to interpretation which can hinder the planning process by providing divergent objectives for each business unit.
- There also has to be commitment and belief in the process for management to supply resources from all affected departments in order to develop an IRP. To the extent these resources have limited availability it hinders IRP development.
- Organizational changes delayed the IRP development at critical times. While this is an everyday occurrence for many historical planning processes without core support and knowledge of the IRP process, those changes are much more critical to developing this new process.

As can be seen from the NMGas experience, the initial step in simply trying to get corporate support for the IRP process and then trying to define and integrate corporate objectives within an IRP framework can be a difficult assignment. However, after three to four months these issues were initially defined.

Figure 4.1

Natural Gas Local Distribution Company Planning Supports Numerous Activities



4.2 Corporate IRP Goals, A Definition of IRP, and IRP Objectives

Corporate Goals

The broad objectives and strategic issues this IRP plan was to address were outlined in NMGas' 1993 Business Plan.¹⁵ The major objectives were to become the most responsive, efficient, gas energy services company in the Northeast and to achieve maximum value for customers, shareholders and employees. In pursuing this mission, NMGas will:

- Provide customers with high quality services that are safe, reliable, competitive and responsive to their needs;
- Maximize long-term shareholder value through aggressive business expansion and earnings growth, and
- Act in a responsive manner, cognizant of the environmental concerns of the communities we serve.

These general goals and issues define the strategic framework for the integrated resource plan. Given this framework, the definition and goal of the integrated resource planning process was developed.

IRP Definition

NMGas defined gas integrated resource planning as a process designed to meet customer utility service requirements in the most cost-effective manner through a combination of supply and demand alternatives. Generally speaking, NMGas views supply alternatives as those options that treat customer demand as given and demand-side alternatives as those options that try to affect customer demand through price, marketing activities (e.g., fuel switching and conservation) or some combination of both.

NMGas was motivated to pursue gas IRP because of regulatory pressure and because they believed it made good business sense. From an organizational standpoint it was felt this process could be instrumental in

¹⁵Niagara Mohawk Gas Business Unit, "1993-1995 Business Plan and 1993 Departmental Goals," Syracuse, New York December 1, 1992.

developing a way of building consensus across all departments that would minimize costs by considering a broader array of options in situations where decisions must be made regarding strategic concerns. From a customer perspective, NMGas was motivated to provide each customer with gas energy service, not just gas. To this end, they started with the understanding that their customers value heat, hot water, air conditioning, clothes drying and cooking. From a shareholder perspective, they were obligated to look for ways to be competitive so that they could maintain, and hopefully, increase their market share in ways that provide sufficient returns to their shareholders.

IRP Objectives

These general corporate goals and IRP definition helped define the strategic framework for the IRP. Given this framework, the objective of the integrated resource planning process was to develop a resource acquisition strategy that, after considering all demand and supply options:

- minimizes the cost of gas services to customers while maintaining required levels of supply reliability;
- maximizes value to shareholders and customers;
- does not adversely affect rates;
- satisfies environmental requirements; and
- is sufficiently flexible so that it can be altered to accommodate the rapidly changing competitive markets in which we will have to operate.

These goals represent not only several objectives but also indicate several possible resource evaluation criteria. For example, minimizing gas costs generally indicates using a Societal or Total Resource Cost Test as a screening tool (see Table 3.2). Maximizing value to shareholders considers the company's stock price and return on equity. Not adversely affecting rates generally indicates the use of a Rate Impact Measure Test for screening resources.

Given these objectives, its current gas supply situation and the threat of competition, the Company decided to use the Rate Impact Measure Test (RIM) in its evaluation methodology.

This is a critical point to recognize because the evaluation criteria or test literally "picks", from an economic perspective, those demand-side programs deemed suitable for the Company to pursue. More importantly, this demonstrates the need for the Company's IRP objectives to be well understood, consistent with corporate goals, and established at the outset to insure that the eventual resource mix reflects these overall objectives.

An additional initial criterion established by the project team was that the focus of the IRP would be on the core business and core markets, i.e., primarily gas sales but also transportation services provided to residential, commercial and industrial customers in the Company's traditional state regulated markets. However, as the process developed, the integrated resource plan eventually addressed issues related to strategic expansion opportunities such as franchise extensions and mergers and acquisitions opportunities.

4.3 Regulatory and Public Involvement

As part of a determination of the IRP strategy it was necessary to consider regulatory guidelines and concerns. In the New York Public Service Commission's Opinion 88-20 regarding IRP for electric utilities, the Commission decided it would be inappropriate to impose a particular IRP methodology on individual utilities. Instead, the Commission affirmed the recommendation that the Commission should endorse the "basic elements and concepts" and not "mechanics and details" of an IRP process.¹⁶ Among the reasons cited by both the Judge and the Commission for this preference were the structural changes underway in the electric industry and the evolutionary nature of the IRP process.

¹⁶Commission Opinion 88-20, pages 14-15 and Recommended Decision of Integrated Planning and Construction/Ratemaking Issues, By Law Judge Frank S. Robinson (January 17, 1988, page 24).

NMGas believed that these same principles applied equally well and perhaps better to the natural gas industry.

Furthermore, the IRP process for electric utilities recommended that identification of goals and objectives initiate the planning process. The judge and the Commission in Case 29409 endorsed this concept as an element of the IRP process and recognized that IRP decisions should be evaluated across many criteria and not by reference to costs alone. The NMGas position on this issue was fully consistent with Commission.

4.4 Rate Design Issues

A critical component to keep in mind when developing an IRP and is the consideration of rates. The essential function of rates is to recover the Company's cost of service, including its authorized return on investment, with the minimum possible risk consistent with applicable legal constraints. Obviously, rate design can be used to further the company's IRP objectives, whether they be used to encourage conservation or strategic load building. However, an essential component of rates to consider is that federal regulations have significant impacts related to rate design.

For example, FERC Order 636 unbundled interstate pipeline capacity and storage services and, except for very small customers, eliminated the pipeline sales functions. Order 636 also changed pipeline rate design from modified fixed variable (MFV) to straight fixed variable (SFV) rate design.¹⁷ It allows interstate pipeline capacity holders to release their capacity to the highest bidder, subject to a cap equal to the pipeline's maximum applicable rate. Finally, Order 636 allows 100 percent of the pipelines' prudently incurred cost of buying out sales-related purchase contracts to be recoverable in rates, with 90 percent of such costs to be passed through to firm transportation customers (primarily local distribution companies (LDCs)) and the remaining 10 percent to interruptible transportation customers.

¹⁷Includes FERC Orders Nos. 636 issued April 8, 1992, 636-A issued August 3, 1992, and 636-B issued November 27, 1992.

Order 636 has affected LDCs in two major ways. First, they can no longer rely on interstate pipelines to provide sales service and long-term supply planning. LDCs have had to take full charge of purchasing gas directly from suppliers and performing the supply scheduling and planning functions. Second, the shift from MFV to SFV ratemaking has increased peak capacity costs for LDCs. As discussed in more detail below, this shift has affected the relationship between LDC supply costs and retail rates, and generally made the IRP process more complex and uncertain.

Interstate Pipeline Rate Design

Under MFV rate design, the demand charge component of interstate pipeline rates reflected the usual array of fixed costs -- rate base, most M&O expense, A&G expense -- but excluded return on rate base and related taxes. Return and taxes, along with costs that varied with pipeline throughput, were included in the variable commodity charge. The FERC's primary reason for this approach was to give pipelines an incentive to improve system utilization.

Under SFV rate design, interstate pipeline demand charges reflect all of the pipeline's fixed costs and variable commodity costs reflect little more than compressor fuel. With all fixed costs covered, interstate pipelines are indifferent to short-run changes in throughput.

All other things being equal, the shift from MFV to SFV rate design has increased peak-day transmission and storage costs for LDCs. LDCs have generally objected to SFV rate design and are pressing for alternate rate designs that would reallocate a portion of fixed costs to the commodity component.

LDC Rate Design

LDC rate design is characterized by volumetric rates for firm residential and commercial service. Larger customers are served under a variety of firm or interruptible volumetric rates, transportation-only volumetric rates, and an even greater variety of firm and interruptible demand-commodity rate forms. Peak capacity costs are frequently reflected, but by no means accurately, in volumetric rates by means of higher winter seasonal rates and lower summer seasonal rates.

Most LDCs also include a purchased gas adjustment (PGA) in their retail sales rates. The PGA typically includes interstate pipeline capacity and storage demand charges, variable transportation and storage charges, and purchased gas commodity costs. The PGA is frequently included in bundled sales rates on a 100 percent volumetric basis.

Interstate Pipeline and LDC Rate Design Relationships

Current interstate pipeline and LDC rate designs interact in many ways. Some are complementary; some are conflicting. Several of the most obvious interactions are summarized below:

- SFV rate design promotes peak shaving, but 100% volumetric PGA rates do a poor job of conveying the cost of peak service. Seasonally differentiated PGA rates can improve the quality of the price signal, but still do not convey the full cost of peak service.
- SFV rate design minimizes off-peak interstate transportation costs, which in turn, provide an incentive to increase off-peak throughput. However, LDC rates may or may not reflect the lower off-peak costs.
- In assigning all fixed costs on a peak capacity basis, SFV assigns no capacity value to off-peak service, even though capacity is needed to render off-peak service. LDC rate designs tend toward the other extreme. For example, a volumetric year-round rate undervalues the cost of on-peak capacity and over values off-peak capacity. Other LDC rate forms have the same defect, but in a less pronounced manner.
- If LDC rate designs were configured to mirror SFV rate design, fixed costs that are now recovered in volumetric rates would be shifted to some combination of higher monthly service charges and demand charges based on peak usage. Such a shift could cause intraclass and interclass rate and bill disputes.

Relationship to IRP

The unbundling of pipeline capacity, storage and gas supply services under Order 636 has several important implications for IRP:

- IRP evaluations have become more complicated because LDCs have more pipeline service options to consider.
- SFV ratemaking increases the value of DSM programs that reduce winter day peak demand and decreases the value of DSM programs that reduce gas use in non-peak day periods.
- If SFV rate design were to be adopted at the LDC level, LDCs would be essentially indifferent to changes in throughput because fixed costs would be recovered through fixed charges and earnings would be unaffected.¹⁸ From an IRP perspective, this would place commodity-related supply-side and demand side options on an equal footing.
- The shift from MFV to SFV ratemaking illustrates the inherent uncertainty of pricing structures. Thus, long-term IRP policies developed under the MFV "reign" may be inappropriate under an SFV "regime." Moreover, IRP practitioners will need to reflect the risk that SFV rate design could be modified in the future.

4.5 Conclusions

This section presents the lessons learned by NMGas when performing this step of their IRP process.

- **A multi-function project team was established to develop the IRP.** This was a small team composed of four to five members with one overall IRP Leader dedicated to the project. This was believed necessary, and later proved beneficial because the IRP process crosses a number of functional areas within the Company. Therefore this collaborative effort was established and proved to be a good means of facilitating the IRP process.
- **There was a need for the team members and senior management to be "committed" to the project.** Without senior level commitment to the process

¹⁸In this context, SFV rate design might be regarded as functionally equivalent to electric revenue adjustment mechanisms (ERAMs) which have been implemented in a number of utilities to compensate them for the lost revenue associated with conservation programs.

coupled with an appropriate priority status the project could be frequently delayed. Furthermore, the project team leader found it critical for task assignments to team members to be communicated precisely. In other words, simply because the team leader understood the requirements of the IRP process did not mean other team members are so knowledgeable and/or had the same understanding.

- **The issue of rates and the relationship of FERC regulations in regard to rate design must be considered.** More specifically, the shift from MFV to SFV could modify future IRP considerations
- **The objectives of the IRP should be consistent with corporate goals.** *This was a critical decision for NMGas since it helped focus their efforts on common objectives.* NMGas concluded that several objectives, which were consistent with their corporate goals, should guide their IRP process. These included minimizing the cost of gas services to customers, maximizing shareholder value, satisfying environmental requirements, developing a flexible plan, and not adversely affecting rates. The latter objective indicated that the appropriate IRP economic evaluation criteria for NMGas at this time would be the Rate Impact Measure test.
- **This initial step in the process took 2-4 months and was completed by the scheduled date of February, 1993.**

Chapter 5

STEP 2: DEVELOPING PLANNING ASSUMPTIONS

5.0 Overview

The purpose of this step was to establish the planning assumptions in which gas IRP strategies would be developed. To this end the project team was responsible for developing reasonable and logically consistent assumptions regarding customer demand, gas supply, and financial status, T&D systems and market structure. From an analytical perspective the goal was to identify and define planning scenarios that would ensure the strategic objectives established in Step 1 would be met through a comprehensive analysis designed to assess risk, flexibility, and in general, maximize insight for decision making purposes.

This Chapter is arranged in the following manner. In the next section the various issues to consider in developing the planning assumptions are discussed. In Section 5.2 the specific factors affecting and how they affect planning assumptions are summarized. In Section 5.3 the planning guidelines established by the Project team are outlined. The chapter closes with a discussion of findings related to the experiences of the development of the planning assumptions.

5.1 Issues Related To Developing Appropriate Assumptions

A long-term planning scenario is a hypothetical future defined by planning variables that either singularly or collectively impact NMGas' core business. Well-defined Business Unit objectives and strategic issues (Step 1) will implicitly determine the planning scenarios and their related planning assumptions that are required to develop a practical and well-thought out long-term gas IRP strategy. These planning assumptions are developed in conjunction with a comprehensive analysis of the business environment. This analysis examined and evaluated the underlying factors that influenced the future environment. These factors include regulatory policies, the dynamics affecting future customer requirements and the dynamics affecting future gas supply. The results were

projections of the components necessary to develop forecasts of customers requirements and of the costs of supply sources.

In addition, this analysis identified the key risk factors that could cause future supply and demand conditions to be significantly different from the forecasts. This risk analysis would generally be utilized to define alternative scenarios to judge the robustness of resource portfolios across a range of potential future outcomes.

An essential aspect of the planning assumptions is a good base of knowledge of the economic and technical potential for demand side measures among the end-user customer base served by NMGas. This project drew upon the results of work sponsored by the New York Gas Group (a confederation of gas LDCs in New York State) and the New York State Energy Research Development Authority. This effort was being conducted by the American Council for an Energy Efficient Economy to review gas DSM potential. As a sponsor of this study, NMGas had access to this research for the development of an IRP. Further, NMGas conducted extensive DSM research and pilot DSM programs among its electric customer base. The knowledge gained of how customers in the NMGas territory respond to energy and DSM marketing initiatives will also be a key input to this project.

5.2 Factors Affecting Planning Assumptions

Macro/Regional Economic Conditions

Macro/regional economic conditions summarize key economic and demographic factors in NMGas' service territory. These factors include population growth, construction activity, employment and income trends, and overall energy price trends. These conditions describe the general state of NMGas market including market growth opportunities. Construction of base, low and high growth scenarios for macro/regional economic conditions is a reasonable approach.

Gas Prices

Burner tip natural gas prices relative to prices of alternative fuels determine natural gas' competitive position in individual end-use markets. This suggests two relative price scenarios:

- Base Case (business as usual) - delivered natural gas prices are generally competitive with alternative fuel prices, including residual fuel oil in the electric generation and industrial sector. Residual oil capable customers occasionally fuel switch based on economics but natural gas is generally the economically preferred fuel.
- High Relative Gas Prices - delivered natural gas prices are high relative to residual fuel oil prices on a sustained basis so that residual capable market is lost. A more extreme case would be that delivered gas prices are above distillate oil prices so that higher valued industrial process and cogeneration load would be threatened.

FERC Regulation

FERC regulation will affect the prices, quantities and terms of service for gas supply and services available to NMGas, its customers and potential customers on and off-system. The base planning scenario would be Order 636 implemented as scheduled. An alternative scenario would be that capacity brokering and market hubs develop to the extent that gas and transportation become "pure commodities." This could affect NMGas' competitive position in various markets.

State Regulation

State regulation will affect the flexibility of NMGas to package and price services to customer segments including customers off-system. There are several reasonable planning scenarios relative to state regulation. The first would be a business as usual case reflecting current flexibility to price and sell services. An alternative would be a policy of preventing LDCs from selling gas supply to non-core markets. A third alternative might be increased flexibility to price supplies and services combined with some type of partial pass-through mechanism to protect core customers and to create incentives for LDCs to purchase and sell gas effectively and efficiently. A fourth alternative

might be unbundling of NMGas services much as interstate pipeline services have been unbundled.

Environmental Policy

Environmental considerations are an important element in future public policy-making. One planning scenario could be continuation of the current situation in which environmental impacts are considered in decisions but in an ad hoc manner. One alternative scenario could be a policy which assigned explicit externality costs to utility resource planning decisions. These externality costs would be differentiated by fuel type based on the environmental damage caused by consumption of each fuel. This would tend to favor natural gas over other fuel types in planning decisions but favor DSM options relative to any fuel consumption. An alternative scenario could be a policy in which an energy consumption tax would be implemented. This would tend to favor energy efficiency over fuel usage. One possible outcome might be greater potential for natural gas vehicles.

Customer Requirements Forecast

The load, demand or requirements forecast is an essential starting point for any supply planning exercise. For purposes of gas supply planning, this forecast must be disaggregated to recognize the business relationship with each customer group. For example, firm and interruptible service must be distinguished, sales and transportation service must be distinguished, the utility standby obligation to each customer group must be recognized, and the requirements of the filed utility tariff for each group must be considered. The sensitivity of the requirements to weather, alternate fuel price and wellhead gas price and availability should be recognized for each group. The gas utility may plan supply contracts and facilities to a requirements level based on extreme weather and high reliance of standby customers upon sales service. In fact, such planning is necessary to ensure the utility is capable of providing the required level of reliability to high priority loads.

Business plans may, however, be forecast based upon expected or normal conditions, with little or no anticipated utilization by standby customers of sales service. Some gas distribution utilities in New York State serve a large interruptible dual-fuel market that is not easily represented by a single

requirements forecast. Instead, the forecast must be referenced to other factors such as alternative fuel prices, which can cause significant discrete changes in demand. In sum, the customer requirements forecast should carefully detail all the uncertainties and variability affecting potential demand for gas. These uncertainties will likely differ from those uncertainties associated with electric load forecasts in nature and magnitude. Therefore, the variables used in the sensitivity analyses for electric demand forecasts may not be useful for gas demand forecasts.

The customer requirements forecast incorporates many other planning assumptions in addition to those discussed above. Examples are service area population and economic growth, price elasticity and trends in end-use efficiency.

Supply-Side Alternatives

The gas price forecast will encompass many planning assumptions for gas supply. Forecasts for other supply components - transportation, storage, bundled supply service, peak shaving facilities, service area storage and emerging technologies -- must be developed. A catalog of all supply alternatives outlining availability, capacity, costs and uncertainties is an essential component of the planning assumptions.

Demand-Side Alternatives

The IRP planning assumptions require a catalog of demand side alternatives recognizing the demand side management programs that have been in effect for many years. This catalog will include estimated impact on demand, costs, penetration rate and other information. Demand side programs include demand shaping, peak shaving, efficiency improvements, new gas burning technology, emerging technologies and beneficial gas demand building. Individual utilities may also target fuel switching either to or away from gas. Unlike electricity, the development of new geographic markets not currently served by gas may be an important aspect of an individual utility's plans. As with supply alternatives, the demand alternatives will be unique for each gas utility. (For a more thorough discussion of gas demand-side options refer to Appendix I.)

Reliability Standard

LDCs generally plan supply and delivery capability to meet, at minimum, firm customer requirements on a design peak day and over the course of an extremely cold winter (design winter). The probability that a day colder than the design day or a winter colder than the design winter occurs is the probability that firm customers will be interrupted. Design criteria are usually stated on the basis of probability of weather extremes occurring. For example, a system may be designed to meet a one year in thirty-year or a one year in fifty-year criteria. Various weather factors such as temperature, wind and prior day's temperatures may be used to define design conditions.

Given the essential nature of gas service for space heating in New York, a premium must be placed on reliability. The NMGas has planning guidelines aimed at ensuring reliable service to firm customers under extreme design conditions. These guidelines are an input into the IRP process.

5.3 Planning Assumptions

There were a number of general planning assumptions required to initiate this project. These initial general assumptions include how various aspects of the IRP are to be modeled. These general assumptions are outlined in the rest of this section. However, it should be pointed out that there are a number of more specific assumptions which the process requires, such as an estimate of customer demand. These other more detailed assumptions and calculations will be outlined in the Company's final IRP document.

General Supply Planning Assumptions

1. The baseload forecast and plan to be developed by NMGas would be three years for an operational plan and 15 years for a longer range forecast and plan.
2. A baseload for high natural gas consumption forecast developed for NMGas which was based on the New York Power Pool Load and Capacity Data, 1992-2008.

3. Specific action plans, goals and objectives for a three-year period and a description of the process by which achievement of these plans would be monitored.

General DSM Related Planning Assumptions

1. Projected a portfolio of DSM conservation and efficiency programs that may be implemented over the next 15 years.
2. Projected impact on gas demand associated with each program including, where possible, identification of demand impacts by geographic area.
3. Identification of activities, timing and costs to implement the DSM programs.

General Facilities Development Assumptions

4. Major planned T&D projects for a 15 year forecast period. (Note: a shorter period may be appropriate here.)

5.4 Conclusions

This section presents the conclusions that can be drawn from NMGas' experiences in this step of the process.

- **Careful attention to planning assumptions and policy guidelines was essential.** *These planning assumptions were critical decisions for NMGas since they define the study parameters and guidelines.* These assumptions eventually determine both the bounds and the outcome of the IRP process.¹⁹

¹⁹There are a number of operational problems that can occur in this step usually related to the determination of specific numerical values. For example, specifying the appropriate load forecast, projected gas price and availability, etc., can be both difficult and contentious.

- **Planning assumptions were subject to revisions.** This was due to the changing nature of the gas industry and related competitive pressures. As one company individual put it, "You can't make these planning assumptions in a vacuum and put them in a box, because they can change quite rapidly."
- **Planning assumptions and policy guidelines must be tailored to the requirements of the gas industry and the Company's strategic objectives.** Again, it is critical to emphasize that for individual LDCs there will be assumptions related to their specific needs, goals, and their service area that must be factored in to any planning scenario used in developing the IRP. Also, while Section 5.3 lists the general planning assumptions there are a myriad of more detailed assumptions and planning scenarios that must be modeled.
- **Completion of this phase of the project was delayed two months.** The delay was caused by personnel resources being diverted to more immediate needs, such as rate case filings.

Chapter 6

STEP 3: IDENTIFYING RESOURCE REQUIREMENTS

6.0 Overview

The third principle component of the NMGas IRP process was the identification of resource requirements. This process follows directly from the planning assumptions, demand forecasts and reliability constraints.

In this analysis, only the supply facilities that NMGas would require to match supply and demand were considered. These facilities include pipeline capacity, storage and peaking capacity. The goal was to determine the additional resource requirements by comparing projected demand to committed supply (facilities) capability. For each planning scenario, the analysis computed the projected demand subject to the reliability standard used by NMGas to determine the minimum quantity of supply and resources needed.

Only interstate pipeline capacity was used to determine resource needs. This is consistent with the unbundling of interstate pipeline services which enables separation of gas supply contracting from acquisition of delivery capacity and with NMGas' supply contracting strategy which includes continual contracting for a portion of gas supply needs. Of course, the gas supply contracting *strategy* will be a part of the IRP strategy.

This Chapter is arranged as follows. The next section describes the planning methodology used, Section 6.2 describes the supply services provided by NMGas and Section 6.3 defines the resource requirements. In Section 6.4 the data used to develop the existing supply/demand situation is used to determine the Company's avoided cost which will in turn be used in subsequent analysis.

6.1 Supply Planning Methodology

The resource requirements were identified by comparing committed supply capability to forecasted customer requirements. This comparison was made

using EMA's gas planning system, SENDOUT, to simulate NMGas operations over the planning horizon.

A critical component of supply planning is forecasting the supply requirements of firm customers under design conditions. NMGas revised its methodology to forecast design demand as part of this plan update. NMGas believes this change in methodology will provide a more accurate forecast of firm demand under extreme weather conditions. The design day forecast methodology utilized a regression model of daily demand in the winter season. This model forecasted total system throughput for a day based on a set of variables that included heating degree days for that day and the previous day, indicators of weekends and holidays, and measures of wind speed and cloud cover. An adjustment is made to the forecast equation derived from the historical year to account for customer growth in future years.

For example, design day demand will be projected for each year of the plan. It will include the projected requirements of all customers NMGas is obligated to serve on a design day basis. It would also distinguish between those who are entitled to sales service and those who are only entitled to transportation service. This distinction is important because it influences the types of resources that NMGas must acquire to meet its reliability standards. The design day demand forecast will be compared to the design day supply capability of currently committed resources. Design day supply capability consists of the maximum daily capability of the firm supply sources which are committed (i.e., cannot be changed). To the extent that supply capability falls short of projected demand in any year, a need for additional design day resources would be required.

A similar analysis will be completed for each of NMGas' reliability standards. These include design winter season and summer season. These comparisons will be repeated for each planning scenario identified in Step 2. These comparisons will be summarized in a table that lists, on a year-by-year basis, the magnitude of additional resources needed to meet each reliability standard.

The reliability criterion associated with each demand is analyzed. Adjusting the demand for the reliability criterion sets forth the resource requirement. For example, the utility may set forth the following:

- a. A criterion to have peak day deliverability equal to the firm load expected on a design peak day with a weather probability of one year in fifty years (design day);
- b. A criterion to be able to supply the winter season demand for all sales, standby and x percent of interruptible demand during a design (one year in ten years) winter season; plus a reserve seasonal capacity equal to x percent of firm volumes;
- c. A criterion to be able to meet all firm load on an extreme weather day occurring late in the winter; and,
- d. Sufficient gas supply contracts to meet all firm (including standby) demand and x percent of interruptible demand.

The resource requirements are determined by quantifying the demands above, including any reserve or safety factor allowances. The identified resource requirement would consist of any shortfall between the total demand and the committed (demand/supply) resources that would be available to satisfy that demand. Selecting the portfolio of demand and supply options that best meets the identified resource requirement becomes the focus of the remainder of the IRP process.

As part of this step, long run avoided costs (LRACs) were estimated based on the existing supply/demand plan. These avoided costs are used in subsequent steps as a common denominator price signal to measure the cost impact of small changes in the overall system supply/demand situation.

An appropriate avoided cost methodology is a component of an IRP process. Because an IRP process involves many functional areas, each with requirements for specific skills and expertise, it requires decentralized analysis. However, since a goal is to develop plans and strategies in each of these areas that are mutually consistent, a methodology is required that will serve as the coordinator or integrator that will ensure all analyses and resulting strategies are consistent. Avoided costs is used to help achieve this coordination and integration (a discussion of avoided cost methodology is found in Section 6.4.

A recent report by Lawrence Berkeley Laboratory (LBL) cited the absence of an avoided cost methodology as a major obstacle to successful gas IRP. The project I utilized an avoided cost methodology that reflects the supply planning process and principles used by NMGas, used the specific supply options projected to be available to the company and incorporated the key supply and demand characteristics that differentiate LDCs from electric utilities. Communication of these procedures will aid the industry in closing the gap cited in the LBL report and facilitate gas IRP development.

6.2 Supply Services

NMGas provides a variety of services to its customers. These services include firm sales, firm transport services, interruptible sales services, interruptible transport services and standby sales service. As for the projected customer demand for each of these services, NMGas publishes a Long-Term Gas Supply Plan Update every year. Current (1994) plans call for an annual growth rate of less than one percent per year in firm sales.

Cogeneration (transportation service) is expected to experience the greatest growth and these loads can affect NMGas' supply plan. First, they create an opportunity to peak shave. NMGas has negotiated contracts with many cogenerators in its territory allowing NMGas to purchase the cogenerating gas supply at its city gate on a limited number of days per year. In return, NMGas pays the cogenerator a commodity price that reflects the cogenerators alternate fuel cost.

These arrangements benefit NMGas because the cogenerator pays the demand charges for the pipeline capacity while NMGas retains the right to use the capacity for a specified number of days during the winter season to help meet firm load. NMGas also receives transport revenue from the cogenerator. The cogenerator benefits because existing pipeline capacity can be used to transport supplies for the project so that the cogenerator does not have to pay for new capacity. This lowers the cost to the cogenerators and improves profitability. Second, these loads will increase the utilization of the pipeline system. This may affect the availability and cost of underutilized capacity, either as interruptible transportation service or as brokered capacity.

6.3 Resource Requirements

Before defining the resource needs, certain criteria were established for any potential substitute service. These included the following.

Comparability of Service is Essential

Comparability of service means that the quality of firm transportation service would not differ depending upon whether the pipeline or another entity is the gas merchant. NMGas has fought and will continue to fight to ensure that this principle is embodied in all pipeline restructuring in which NMGas is participating. NMGas believes that comparability of service will be achieved by ensuring that proposed operating parameters are uniform for all buyers, that operational constraints are reasonably intended to guarantee operational reliability, that penalties associated with violating operational parameters are cost-based, and that an adequate no-notice firm transportation service is provided. No-notice transportation is needed to provide the flexibility to manage the daily swings in load inherent in gas operations.

Reasonable Access to Pipeline System Storage Capability is Essential.

Adequate storage is necessary to achieve reasonable purchase load factors on gas supply contracts to help manage daily fluctuations in supply and demand and to provide supply for incremental demand in colder than normal winter weather. NMGas recognizes that pipeline must retain sufficient storage to manage day-to-day operations on their system. However, storage in excess of the amount necessary to maintain operational integrity should be made available to LDC customers. NMGas has pushed in restructuring proceedings to acquire as much storage as possible. This reflects the direct benefits to NMGas of access to storage, the fact that the cost to develop new seasonal storage capacity is significantly higher than the embedded cost of existing storage and NMGas' expectation that any storage not needed for firm sales customers will have value to its end-users, gas sellers and other LDCs.

Reliability Standards

One open issue facing NMGas is the extent to which it is appropriate for NMGas to protect against either failure of a supplier(s) to deliver per their contract(s) or failure of pipeline services. Unbundling of pipeline services will result in NMGas purchasing gas supply from multiple gas suppliers and purchasing transport and storage services from pipelines.

Uncertainty

The biggest uncertainty regarding gas market volumes in NMGas franchise areas is the evaluation of the electric generation market. Gas supply sees three factors as most critical to gas volumes in this market. First, Niagara Mohawk is examining ways to improve its electric competitive position. This may affect the mix of generating capacity it keeps on-line, may lead to capacity retirements and may result in repowering of capacity. This could increase or decrease gas use depending upon the generation asset decisions made. Second, Niagara Mohawk has gained the right to schedule electric production at numerous cogeneration plants and is negotiating to gain that right with other cogenerators. This would decrease gas consumption. Third, the possibility exists that some large electric customers could choose to self-generate and natural gas would likely be the primary fuel for self-generation. This would increase gas consumption.

NMGas' resource requirements were determined by the company's obligation to deliver sales gas under extreme weather conditions to customers with firm entitlements. These weather conditions can be summarized as design-day, design-winter season and design-summer season.

The analysis indicated that NMGas would have substantial supply capability beyond that necessary for firm demand. This under-utilized capability could be used for system generation or end-use transport customers or brokered to off-system customers. Over the planning horizon, no additional resources beyond those in the Order 636 restructuring plan and planned peak shaving are necessary to meet projected summer season firm demand.

SENDOUT was used to simulate the dispatch of supply sources projected to be part of NMGas' supply portfolio. The purpose of this simulation was to ensure

that adequate supply capability was available under design weather conditions and to examine the purchase load factors of NMGas' anticipated gas supply contracts. Simulation results confirm that NMGas has adequate design winter season and design day supply capability throughout the planning period.

6.4 Avoided Cost Methodology²⁰

As part of this phase of the project the Company's avoided costs were calculated based on the data developed in establishing the current supply/demand relationship. These avoided costs were used in subsequent steps as a common denominator price signal to measure the cost impact of small changes in the overall system supply/demand situation.

The term avoided cost was first developed in connection with the Public Utilities Regulatory Policy Act of 1978 (PURPA). As used in PURPA, it represents costs that an electric utility would be expected to incur "but for" the supply of capacity and energy from a PURPA qualified cogeneration facility. The "but for" costs include both the fixed, or capacity, costs not incurred as well as the dispatch or energy costs not incurred.

A simple illustration of avoided costs compares costs of two scenarios. In the first scenario, demand requirements are met solely by utility capacity additions and energy supply. In the second scenario, a non-utility resource is represented. As a result of this resource, the utility can defer or eliminate new capacity and provide a lesser amount of energy. The difference in the utility cost, both fixed and variable, between these two scenarios is the avoided cost for the specific non-utility alternative resource.

While originally developed for use in the pricing of cogenerated and small renewable power, the avoided cost concept was also applied to demand-side management. In Case 28223, the New York Commission recognized the avoided costs of demand-side programs as a means for utilities to measure the cost savings of demand-side management measures. The avoided costs of a demand-

²⁰Avoided cost and marginal cost are sometimes terminology interchanged. Whether this is academically correct is not an issue to be resolved here, rather the avoided cost as used in the paper was defined as marginal cost in NMGas' draft IRP.

side program are the fixed (capacity) costs and variable (dispatch) costs not incurred because of implementation of a load reducing the program.

The practical application of avoided costs to demand-side management (and for that matter, non-utility power generation) is more complicated than the simple discussion above implies. In evaluating many demand-side management programs, the avoided costs could potentially be unique for each program, due to the differing impact on the load shape. Further, avoided costs may change as the number of alternatives (e.g., demand-side management measures) changes. As more load reducing demand management is added, less use will be made of more expensive gas supply, and the savings of deferring capacity contracts or facility additions will occur further in the future. Hence, all else equal, avoided costs will tend to vary inversely to the supply of alternative resources. As used herein, alternative resources refer to any non-traditional utility initiated resource alternative. For gas utilities, demand management is the most likely alternative resource. Demand-side management includes both cost effective demand reduction and cost effective demand building.

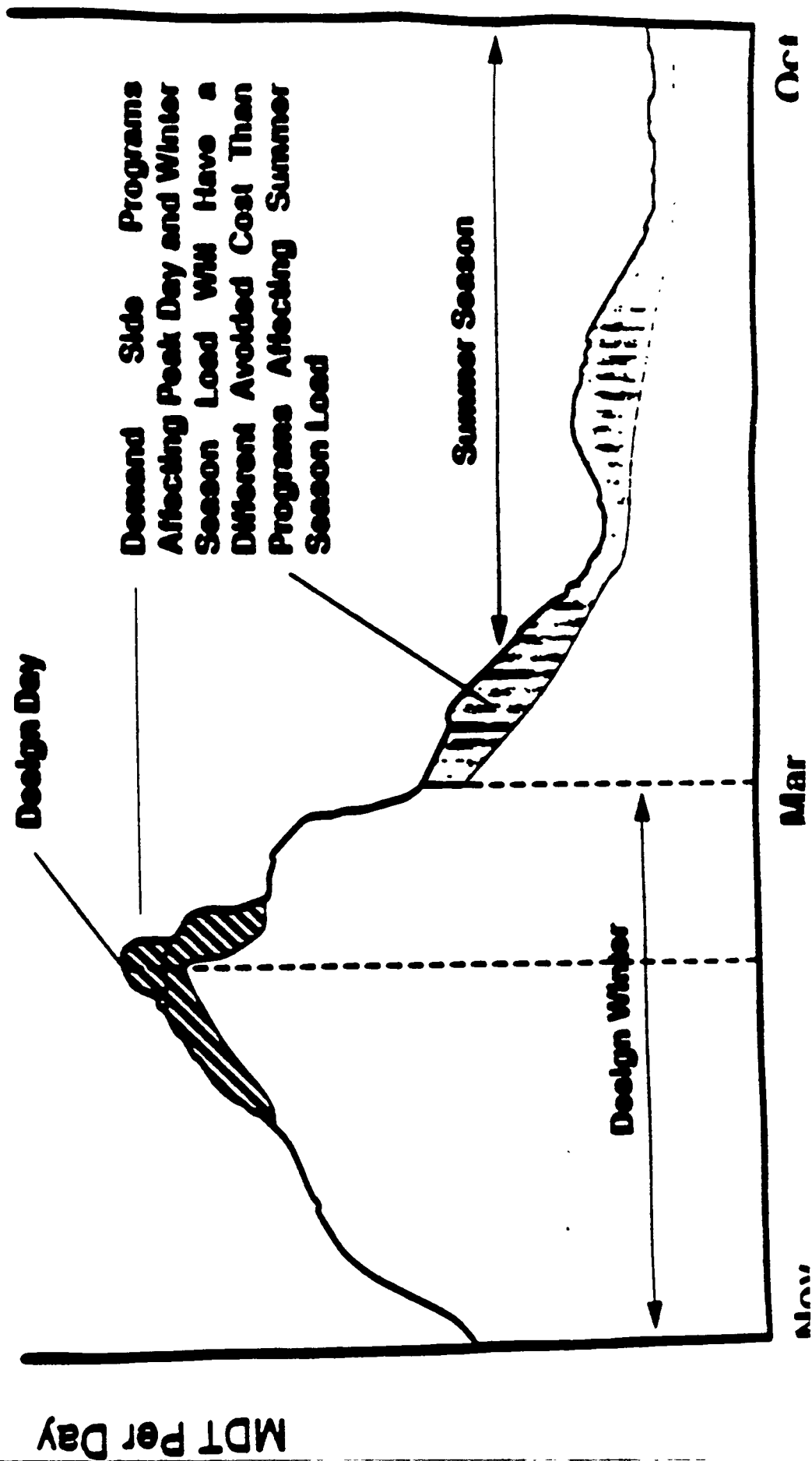
In addition, many of the alternative resources (demand-side programs) examined are small on an individual basis. The impact of each individual program is difficult to capture in a planning analysis. In fact, individual programs may provide little opportunity for capacity deferral. However, an aggregate of programs may enable capacity deferral.

Figures 6.1, 6.2 and 6.3 illustrate these concepts relative to a daily load shape profile characteristic of a typical gas utility.

The most accurate estimation of avoided cost will recognize both the changes in avoided cost brought about by planned development of alternative resources and the opportunities for capacity deferral that result when a small program is considered as part of a larger portfolio of alternative resources. In order to be accurate, avoided costs for a program must also consider the load shape of the program. One way to capture these effects in evaluation is to develop avoided costs for specific programs by the application of LRACs. LRAC's are developed on a forecast basis for each measure of demand that could potentially affect

Figure 6.1

Avoided Costs Will Depend Upon Load Shape Impact



MDT Per Day

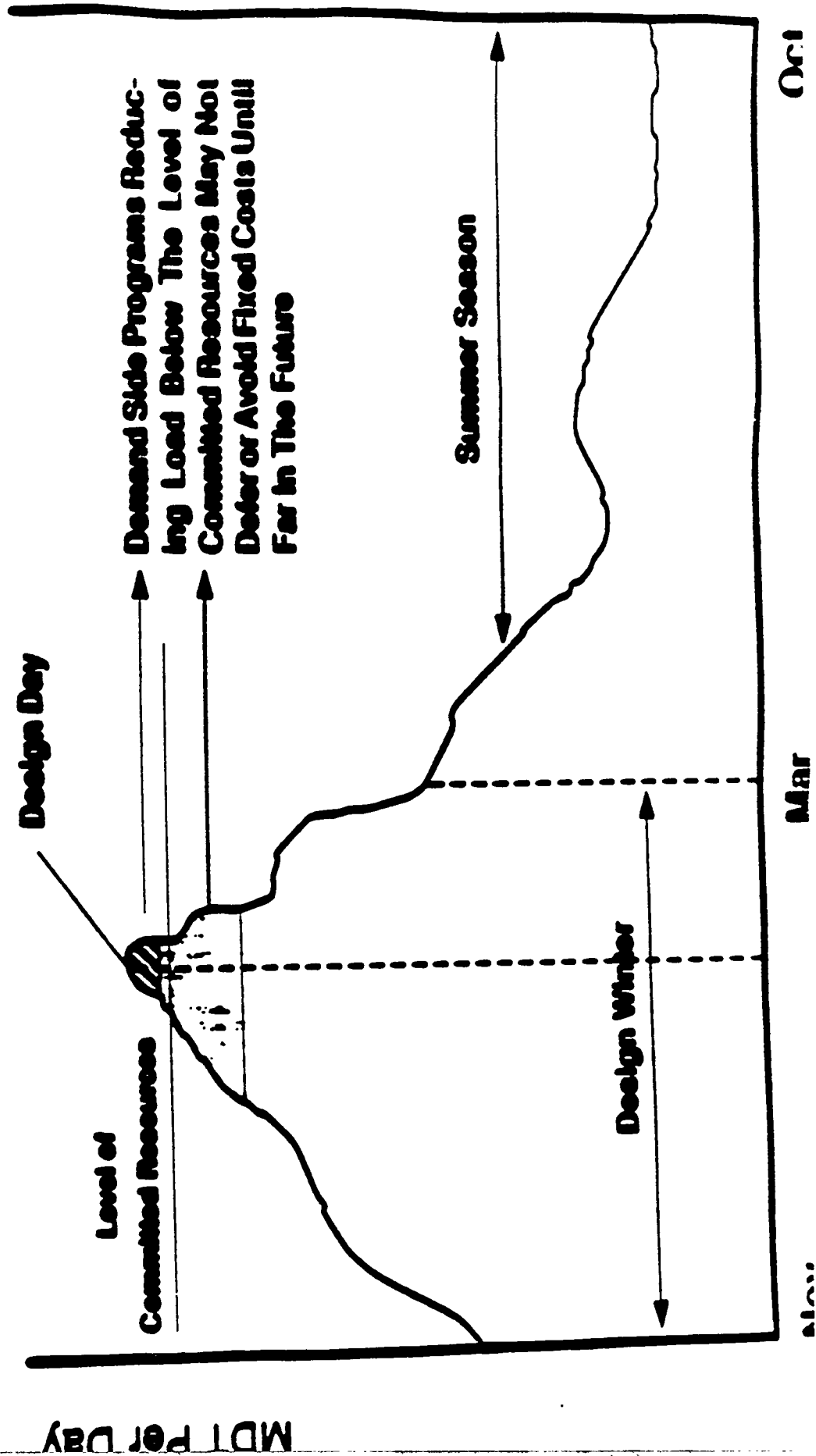
Nov

Mar

Dec

Figure 6.2

Penetration of Demand Management Programs May Affect Avoided Costs



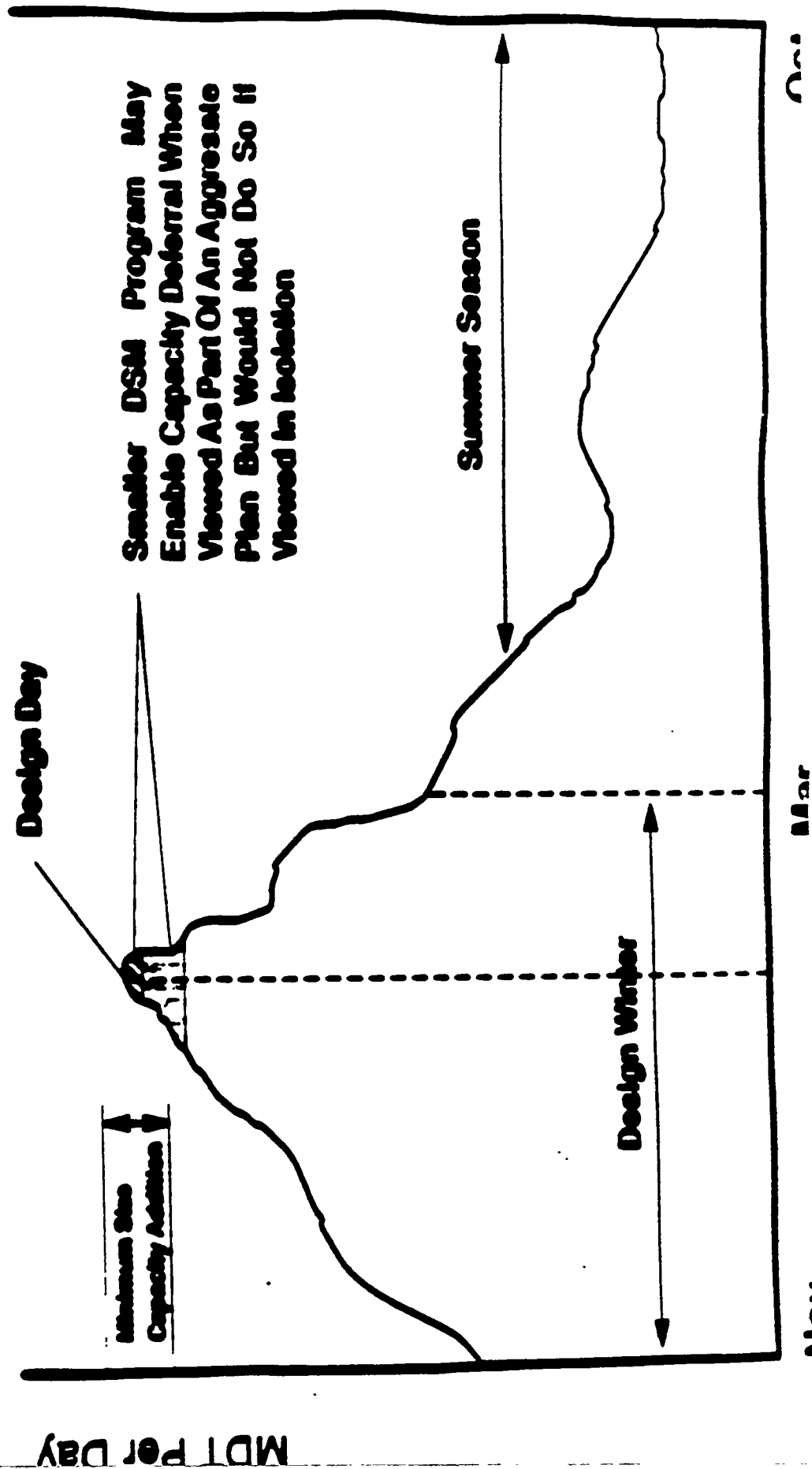
Oct

Mar

MDT PER DAY

Figure 6.3

Small DSM Programs May Be Difficult To Examine In Isolation



Nov Mar Nov

capacity or commodity costs. LRACs are developed on a time-differentiated basis to determine the avoided costs of programs with various load shapes. In estimating LRACs, an assumption is made concerning the anticipated development of alternative resources. This assumption will reflect the relationship between avoided costs and the level of alternative resource development. Initial LRACs are developed assuming the divisibility of large discrete projects in order to reflect the ability of a small program to defer capacity when viewed as part of an aggregate. As will be discussed later, both these assumptions must be checked for reasonableness at various points in the IRP process.

In practice, the actual calculation of avoided costs is a two-step process. First, LRACs are estimated. Second, these LRACs are applied to the load shape of the program to determine avoided cost. LRACs are estimates of how an LDC's costs will change, at the margin, in response to a change in demand. For these estimates to be reasonably accurate, they must be developed using the same principles and practices that are used to plan investments in facilities and contracts for supply and supply services. These estimates should also reflect the dispatch practices and procedures of the LDC. Avoided cost estimates should be a natural output of the resource planning process and should be developed to be consistent with operating practices.

In sum, the term *avoided costs* encompasses two different concepts. First, there are LRACs. LRACs are forecasts of the marginal cost per unit of capacity or commodity that are used as guides for estimating the savings that will result from demand reducing programs or the extra costs that will result from demand building programs. Second, there are program avoided costs. These are estimates of the impact of a program upon overall costs that are developed by applying LRACs to program load shapes.

LRACs have three distinct roles in the IRP process discussed below.

Screening Resource Options (Step 5)

During the screening phase, LRACs are used to develop the costs associated with demand building options and the savings associated with demand reducing options. LRACs may also be used to measure the benefits of certain supply alternatives for screening purposes. These

analyses provide an initial economic ranking of alternatives that can be used as a guide to the development of resource portfolios.

Integrated Evaluation of Resource Portfolios (Step 6)

During the integrated evaluation of resource options, portfolios of demand and supply alternatives will be developed. Initial screening results will guide development of these portfolios. However, as the supply/demand mix in a portfolio changes, LRACs associated with the plan will change. This indicates that an iterative approach to estimating LRACs and using LRACs in resource option evaluation is appropriate. This iterative process would use initial LRACs to guide resource option screening and integrated resource development. LRACs would be revised based on the integrated portfolio plan. These revised LRACs would be used to ensure that the resource decisions reflected in the plan are consistent with the revised LRACs. If LRACs change significantly, substantial rescreening of resource options and integrated portfolio development may be required. More likely, revised LRACs will be used as a guide to refine the resource options included in the portfolio.

Implementation Plan (Step 7)

The aggregate impact of the IRP should be communicated back to the LRAC process as resources are implemented on both a periodic and special event (large deviation from plan) basis. LRACs should be redeveloped in response to changes in the resource mix, forecasts, or energy price. Updated LRACs may produce revisions of the IRP. For example, if plans for a needed supply facility addition were changed because other participants ceased support for the project, LRACs would likely increase as a more expensive supply facility were substituted. This increase could cause an increase in DSM emphasis in the rate design area. Revised LRACs would send the signal to different activity areas to revise plans.

In summary, LRACs have the potential to facilitate the IRP process. There are four guidelines that should be followed in utilizing LRACs in the IRP process. They are:

1. LRAC estimates must reflect realistic estimates of actual utility costs.

2. LRAC estimates should be recognized as a reflection and summarization of many forecast elements.
3. LRAC estimates must be sufficiently detailed to permit evaluation of a wide array of activities with different impacts on demand.
4. Initial LRAC estimates can be developed from a plan that includes only committed supply and demand activities. These initial estimates provide a basis for economic screening of load building and load reducing activities.

A thorough discussion of the development and implementation of avoided cost in a Gas IRP can be found in a report entitled "Integrated Resource Planning for New York's Natural Gas Distribution Facilities", New York Gas Group Member Utilities, 500 Fifth Avenue, New York, New York.

6.5 Conclusions

In this phase of the project the following conclusions could be drawn from the implementation process.

- *The major conclusion of this step is that NMGas would have sufficient supply resources and related transmission capacity beyond that necessary to meet projected firm demand.* ²¹ *This is a major conclusion that affects how a company's IRP proceeds. For example, as opposed to a load reducing demand-side program being used as a substitute for projected new supply resources, those demand-side programs are now being considered as "replacement" energy for supply resources already committed. To the extent those projected new resources might be more expensive than resources already obtained and/or if those current supply resources have firm contracts this can affect the economic evaluations.*
- **It was necessary to establish resource criteria.** *These were critical decisions to establish because they focused NMGas' search on resources that met the Company's predefined criteria in regards to comparability of service and reliability.*

²¹In establishing this finding the Project Team found beneficial the use of SENDOUT software which was used to simulate the dispatch of supply resources under various demand scenarios.

- **Gas resource planning is likely to focus on multiple demands.** This can include peak day, peak season, etc. Unlike electric utilities where the ability to meet peak demand generally enables all energy requirements to be met, gas supply capability often has volumetric as well as capacity limits. Hence, it will not be unusual to focus on multiple demands for gas utilities in setting resource requirements.
- **Gas utility planning criteria for individual gas utilities may differ more than planning criteria for electric utilities.** NMGas, being a combined utility was in a somewhat unique position to make this observation. For example, electric utilities in New York all maintain the same reserve margin criteria. While criteria for electric utilities outside of New York differ, they are similar in both nature and magnitude to those used by New York's electric utilities. There is likely to be more disparity in reserve margins among gas utilities. These differences result from market and supply differences, which mean gas utilities are likely to be less homogeneous than electrics and have (for good reason) reliability criteria that differ.
- **A theoretically sound avoided cost methodology was defined for gas utilities that can be used in the economic evaluations of resource options.**
- **This phase of the project was completed on time (July, 1993).**

Chapter 7

STEP 4 : IDENTIFYING DEMAND AND SUPPLY OPTIONS

7.0 Overview

The purpose of this step was to identify the various supply-side and demand-side options available to the Company for consideration in meeting its projected energy needs. However, recall in the preceding chapter it was determined that the Company's current capacity and commodity supply situation was sufficient to cover expected demand over the time period of the IRP. Therefore, in this step of the process it was only necessary to consider demand-side options. While this circumstance was proper for NMGas, for a company that had insufficient supply options the analysis would include capacity alternatives as well.

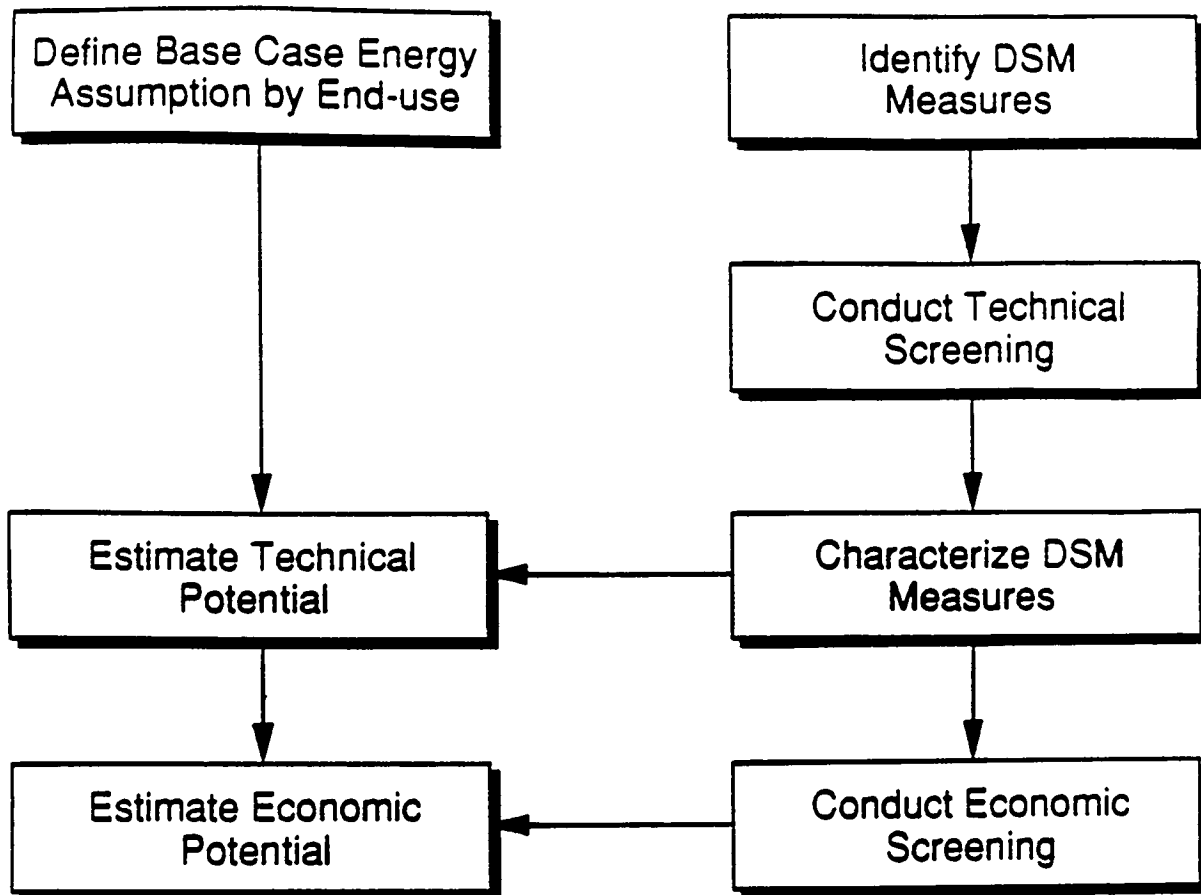
Thus the focus of this step was to determine the identity, availability and size of the DSM²² options for NMGas' service territory. The typical approach used for this process is illustrated in Figure 7.1. The base case characterizes the energy usage of the utility's key market segments and end-uses. In creating the base case and calibrating it to the utility's system-wide forecast, important insights are obtained about customer energy use and a starting point for estimating the impacts of various DSM measures is determined.

The approach continues with a series of analyses to estimate the savings that can be achieved through potential DSM measures. This step begins with a comprehensive list of DSM measures for each customer segment. Each measure on this list is subjected to two screens to evaluate its potential: a technical screen and an economic screen. Measures that pass the technical screen are applied to the base case to determine the technical potential. Measures that then also pass the economic screen are used to estimate the economic potential. Only those measures showing both technical and economic potential are considered for inclusion in DSM programs.

NMGas was responsible for the development of one study to determine the technical and economic potential for residential DSM, and another to determine

²²See Appendix IV for a discussion of gas demand -side resources.

Figure 7.1



the technical and economic potential for commercial DSM. Each study is discussed below. This chapter closes with some observations regarding this phase of the project.

7.1 Residential Technical and Economic Potential Study

The objective of this study was to estimate the technical, economic, and marketability potentials for residential gas conservation and fuel switching.

A base case for the residential sector was developed using data for 790 NMGas residential customers who participated in a 1987 on-site survey. The original sample was selected from NMPC's electric customers, 790 of which were also NMGas customers. The on-site survey provided data on type of basement, square footage of home, type of space heating fuel, primary heating system, indoor thermostat setting, number of occupants, age of the occupants, total household income, number of doors and windows and roof type.

The data from the on-site survey were merged with data from the 1991 New York Home Insulation and Energy Conservation Act (HIECA) energy audit database to obtain information on current attic, floor and ceiling insulation levels; number of storm windows and doors; existence of weather stripping and caulking in windows and doors; and technical feasibility of installing building shell measures.

Sample results from the 790 customers were extended to the entire residential population using 30 strata defined by region, space heating fuel and annual natural gas consumption.

The technologies considered in the study included nine building shell improvement measures, three efficient gas space heating systems, one efficient gas water heater and two air supply and control measures. The electric-to-gas fuel switching measures considered were three gas space heating measures and one gas water heating measure.

The criteria used for the technical screen were applied for each of the 790 customer/dwellings in the sample. Examples include, insulation for which the existing R-value must be less than the targeted R-value, and weather-stripping, caulking, and storm windows that are not already installed. The high-efficiency gas furnace measures were only considered technically feasible for dwellings with either an electric baseboard system, oil furnace system or a gas furnace with an AFUE less than the AFUE targeted in the DSM program.

The DSM measures were characterized using a variety of data sources and the results of simulations run on the 790 homes. Electric and gas heating and cooling loads were calculated for each home based on indoor and outdoor temperature difference data using an engineering simulation model called R-gasDSM. This model was developed for this study. Energy savings per measure were then calculated as the difference in these loads with and without assuming the DSM measure installed.

The technical potential was estimated for each measure that passed the technical screen by extrapolating the savings for that measure for each of the 790 homes to the portion of the population it represented and then aggregating the savings across all home-types. This aggregation assumed 100 percent penetration of the measure wherever it was technically feasible (i.e., regardless of whether the existing equipment was at the end of its useful life or not).

The measures passing the technical screen were then subjected to an economic screen. The study compared the cost of the measure to customer bill savings ("the point of view of the adopter"). This is rather unusual for an economic screen in that it in essence says that a measure is "good" from an economic point of view if it looks "good" to the customer.

The purpose of the economic screen is to determine which of the DSM measures are appropriate for consideration in programs. The appropriate criteria for an economic screen depends on the goals of the utility in its IRP. Four goals are typical - each being the minimization of one of the following: rates, revenue requirements, total resource costs (total energy service costs or total costs to all ratepayers) or total costs to society. The economic screen for a rates goal would compare customer bill savings (revenue loss) to avoided gas costs. The next two

goals have the same economic screen - to compare the cost of the measure to the utility's avoided costs - and the last goal's screen modifies this by adding environmental benefits to avoided costs.

Given NMGas' goals for its IRP discussed in Section 4.2, the appropriate economic screen would have been the Rate Impact Measure (RIM) test. Indeed, as the Company eventually developed its IRP this was the ultimate criterion established.

In the this study a DSM measure was considered to be economically feasible if the customer's rate of return from investment exceeded the customer's hurdle rate of return. The hurdle rate of return (acceptable rate of return) for each customer was said to depend on their financial status, their attitude toward risk, and the availability of other investment opportunities.

An economic feasibility assessment was only done for customers whose existing space and water heating equipment was predicted to fail during the current year. The economic potential was estimated for each measure that passed the economic screen by extrapolating the savings for that measure for each of the 790 homes to the portion of the population it represented and then aggregating the savings across all home-types.

Key findings of the study were that attic insulation upgrading, high-efficiency gas furnaces and clock thermostats were the residential technologies projected to have the highest economic potential for NMGas. The high-efficiency gas furnace was said to have probably the best potential for a program since the economic potential estimates were based on those customers whose furnaces were expected to fail in the current year. These customers tend to make their purchase decisions without much delay. In contrast, customers upgrading attic insulation or installing clock thermostats are not under any time constraint.

Switching electric baseboard heating systems to high-efficiency gas-based heating systems, upgrading wall insulation, high-efficiency gas hydraulic system, and supply air duct insulation all have moderate economic potential. The remaining DSM options have a low economic potential.

7.2 Commercial Technical and Economic Potential Study

This study extrapolated the results of a 1992 ACEEE study for New York State Energy Research and Development Authority and the New York Gas Group on the potential for gas energy efficiency and fuel-switching in New York state to NMGas' service territory.

The base case for the commercial sector for both the ACEEE study and this study was built up using building simulations on DOE-2 of six prototypical building types (office, retail, hospital, supermarkets, restaurant and warehouse) with up to two HVAC systems (office and retail were each separately examined with both a packaged and a central HVAC system). These prototype building types were extrapolated to the NMGas service territory using NMGas floor space by building type, gas end-use saturation and gas end-use EUI data.

The technologies considered in the study included ten gas space heating, seven gas water heater, and five gas cooking energy efficiency measures. The electric-to-gas fuel switching measures considered were four package heating/cooling, five space heating, four space cooling and two cogeneration measures.

The technical screen consisted of mapping of DSM measures to commercial building types. Technical applicability as a fraction of the building floor area was said to be derived from the saturation of measures in the service territory.

The DSM measures were characterized using a variety of data sources and the results of engineering calculations and simulations on the six building prototypes. The energy effects of the ten gas space-heating measures, including interactive effects, and the fuel switching measures were calculated using DOE-2. The energy effects of the seven water heating measures were estimated using engineering estimates, and the five gas cooking measures were estimated with a spreadsheet model developed by ACEEE. Equipment cost and life expectancy data were developed based on either the most recent estimates available in the literature or information developed specifically for the New York State region.

No technical potential estimate was made in terms of energy saved in this study. The only information reported as a result of the technical feasibility analysis is percent applicability figures for each measure for each building type. For example, the power burner range gas cooking measure has an applicability factor of nine percent. That is, this measure is applicable for consideration for nine percent of the gas cooking load. The applicability factor is calculated as the equipment type percent of total cooking equipment (26 percent) times the difference between the technical feasibility of the measure (23 percent) minus the existing penetration of the measure (one percent).

The measures passing the technical screen were then subjected to an economic screen. The study compared the cost of the efficiency measures to gas avoided costs. Since there "is no consensus on gas avoided costs" measure costs were levelized and then compared to a range of gas avoided costs. This comparison represents the perspective of the utility and all ratepayers. If a measure has costs that are lower than the gas avoided cost, it is a "good" measure to consider for DSM programs if the overall goal is lowering either revenue requirements (total costs to the utility) or total resource costs (total costs to all ratepayers). The fuel switching analysis calculated a break-even cost of gas in their economic analysis. If gas avoided costs are lower than the break-even cost, the fuel switching technology passed the economic screen.

Given NMGas' goals for its IRP discussed in Section 4.2, the appropriate economic screen would have been the RIM test which, as the Company eventually developed its IRP, was the ultimate criterion established for this initial IRP.

Because of the uncertainty of avoided gas costs, the study's results were presented in supply curves and as percentages of end use and sector energy use saved by building type and across the system under each avoided gas cost scenario. Sensitivity analyses were also performed to look at the variation in those percentages given measure costs decreasing by 25 percent, or increasing by either 25 or 50 percent. The analysis assumed that all measures were retrofits, and that the space heating, water heating, and cooking equipment up-grades would only be considered at the time of equipment replacement.

The study shows that the economic savings potential in NMGas' commercial sector is 22 percent assuming avoided gas costs of \$3.50/DTh and 23 percent assuming avoided costs of \$5.00/DTh. These results indicate little sensitivity to the avoided cost of gas estimates - at least within the range tested. Other key findings were that significant cost-effective savings are available from space heating loads. However, despite the cost-effectiveness of water heating and cooking measures, these savings would only account for a small portion of total gas load. From a building type perspective, the greatest source of cost-effective commercial sector gas savings is in the office, retail, and hospital sectors.

The fuel switching analysis showed that for packaged HVAC compared to electric heating, the packaged desiccant system is the most cost-effective for office and retail, but all technologies are cost-effective for all building types except warehouse against this base. Against a base of gas heating and electric cooling, the packaged gas engine cooling/heating system is cost-effective for the office and warehouse. For the central HVAC system analysis of heating, both the standard and high-efficiency gas alternatives were highly cost-effective.

7.3 Additional Analysis of Commercial Base Case and Establishment of Industrial Base Case

SRC prepared a working paper for NMGas called "Gas and Electric Sales Profile Working Paper" in February 1994.²³ Although the paper was finished after all the analysis for Steps 4 and 5 were completed, it documents a gas sales profile analysis performed by SRC as the basis for their commercial and industrial analysis described in Step 5. A sales profile serves the same purpose as the base case described above (i.e., it breaks down sector sales into customer segments and end uses).

The purpose of the working paper was to describe the framework used by SRC in the development of commercial and industrial gas sales profiles for NMGas. It is intended to provide guidance to NMGas DSM program planners by illustrating the procedures used to develop natural gas and electric sales profiles using currently available data. SRC's analysis in Step 5 used the RTI data.

²³See Balakrishnan (1994).

described above for the residential sector. SRC's analysis of the commercial sector described in the working paper supplemented the study discussed in Section 7.2.

7.4 Conclusion

This section presents the lessons learned by NMGas when performing this step of their IRP process.

- **Start with a load shape screening.** This IRP process, as well as many others performed in the past, began this step with a list of DSM technologies. Considerable work went into creating the data needed to analyze each of these technologies and to determine whether it should be considered further in the IRP process. The work performed in this step could have been shortened and focused by beginning with a simple load shape screening analysis.

The analysis simply calculates the avoided gas cost and the revenue loss for a increment of gas savings (say, one therm per month) for the peak day, across the winter months, across the summer months and across the year. The avoided gas cost for each period gives the amount that can be "spent" on DSM per therm depending on the utilities IRP goals. The dollars "spent" can be incremental customer costs plus utility administrative costs without increasing resource costs or costs across all ratepayers. The dollars "spent" can be utility administrative and incentive costs without increasing revenue requirements. The avoided gas cost minus the revenue loss for each period gives the amount that can be "spent" on utility administrative and incentive costs per therm without increasing rates. Notice that if the amount that can be "spent" is negative, no DSM technology that saves therms in that period will pass. In fact, this is an indicator that load building programs should be considered. This screening process can give an early indication of the types of measures that should be considered for the IRP, thus saving the effort and time needed to fully characterize a list of technologies that are not appropriate with respect to the utility's goals.

To screen fuel-switching options, gas and electric avoided costs, and gas and electric rates can be used to determine the gas to electric use ratio that a technology would need to be above before it should be included. The technology list could then be shortened to only those meeting the ratio requirements before equipment cost and other data are developed.

- **Make sure the economic screening criteria match the goals of the IRP.** *As already discussed, it is critical to coordinate the objectives of the company with the objectives of the IRP and subsequently the economic screening criteria.* Two different economic screening criteria were used in NMGas' analysis for this step. The economic screening criteria should match the goals of the IRP. It is not often that the goal of a utility's IRP is to lower costs to only those customers who participate in a program (ignoring the rate impact imposed on all other customers). Yet this is the goal implied by the use of a customer perspective in the economic screening analysis.

What eventually occurred in the IRP process was the Company used the RIM Test as the economic criteria with which to establish a program's acceptability. This test, as discussed in Section 4.2 is consistent with the overall strategic goals of the Company.

- **The information gained through the base case and sales profile analysis is valuable beyond the IRP process.** While the base case and gas sales profile analyses struggled with limited data, the information generated by these studies is still highly valuable to NMGas. Sales data per sector by customer segment and end use is valuable for any type of marketing NMGas may wish to do, including new rates, load building, load retention, and customer services. This data has been made available to the appropriate departments at NMGas.
- **The revised date of completion for this phase of the project was August, 1993, and both of the initial studies were completed by that date.**

Chapter 8

Step 5 : Screening Demand and Supply Options

8.0 Overview

The purpose of option screening is to rank options. Clearly inferior options can be eliminated, clearly superior options identified for priority analysis and the remainder characterized and ranked for further analysis. Screening of options can consider all factors that are relevant to distinguishing among options. These factors may include, inter alia, economic or cost factors, risk factors and environmental impacts.

In many instances, cost is a primary screening criteria. The intent of cost screening is to provide an objective basis to compare resource alternatives. Cost screening for demand side options involves comparing the costs of demand side options to the benefit of those options. Those benefits are the supply alternative cost savings (avoided cost) resulting from demand side implementation.

The Chapter is arranged as follows. The next section discusses the general process of screening demand-side options followed by a section that discusses NMGas' specific screening process. Section 8.3 describes how various programs can be combined into portfolios of DSM options. Sections 8.4 and 8.5 discuss the issues and methods related to the actual cost evaluation of various demand-side programs. This chapter closes with a summary of the lessons learned by NMGas from this step in the process.

8.1 Screening Demand-Side Options²⁴

The purpose of this step is to take the DSM measures that pass the technical and economic screens performed in Step 4, combine them into programs, and then determine which are appropriate for inclusion in the integration process (Step 6). The work performed as part of this step is made up of three main tasks.

The first task is to combine the DSM measures that pass the technical and economic screens of Task 4 into program concepts. Several measures may be

²⁴See Appendix I for a thorough review of gas demand-side programs.

grouped into one program based on factors such as the similarity of targeted end uses and a common vendor framework.

The second task of this step is to fully characterize the programs. This task involves three subtasks. The first is to take the annual energy savings estimates developed in Step 4 and determine the timing of those savings and their peak day impact. The second subtask is to determine market penetration. The market penetration for a program depends both on the size of the economic potential (determined in Step 4) and the likely customer acceptance of the technology and program design. The third subtask is to estimate utility administrative and incentive costs (incremental customer costs were developed in Step 4). Utility administrative costs include all the costs to the utility of developing, marketing (other than the direct customer incentive), administering, monitoring, and evaluating the program. Utility incentive costs are the dollar amounts given by the utility to the customer to encourage participation in the program.

The third task of this step is to determine the cost-effectiveness of the programs. Cost-effectiveness analysis is related to, but goes beyond the economic screening done in Task 4. A DSM program is considered cost-effective if the benefits of the program exceed its costs. The definition of the benefits and the costs of a program depend on the goals set by the utility for its IRP. For example, if the utility's goal is to minimize rates, the benefits of a program are those dollar impacts of the program that tend to reduce utility rate levels and its costs are those dollar impacts that increase rates. Given NMGas' goal for its IRP defined in Section 4.2 a DSM program would be considered cost-effective, and thus go on to be considered in Task 6, if the program's benefits are greater than its costs from the point of view of the RIM Test.

8.2 Technical and Economic Screening Analysis

NMGas coordinated this screening process through an outside contractor, SRC. They began the Step 5 analysis by performing a technical and economic screening analysis for each sector: residential, commercial and industrial. SRC repeated some of the work performed in Step 4 for the residential and commercial sectors in order to create and check the inputs needed for their cost

effectiveness analysis model (COMPASS). This analysis was essential for the industrial sector since no technical and economic screening had been performed in Step 4 for the industrial sector. The residential sector analysis was based on the work described in Step 4. The commercial and industrial sector technical and economic screening analysis was written up in the working paper described in Step 4.

The technical and economic screening analysis analyzed seven residential sector, eleven commercial sector, and seven industrial sector energy efficiency measures. Two of the residential measures and one of the commercial measures were also considered for fuel switching. One additional measure was considered only as fuel-switching for the industrial sector.

Although process heating was determined in the technical analysis to be the largest industrial end use consumer, it was not included in the economic screen, nor in the rest of the Step 5 analysis.

The economic screening analysis performed by SRC screened technologies from the point of view of the customer. As discussed earlier, the appropriate screening criteria for an economic screen depend on the utility's goals for its IRP, which for NMGas in this initial IRP would generally indicate the use of the RIM test.

8.3 Combining Measures Into Program Concepts

SRC's use of the customers' perspective for an economic screen does, however, serve another purpose. A screen from a customers' perspective is useful for program design. It is reasonable to assume that a different marketing approach should be taken for measures that have a relatively short payback for customers than for those with a longer payback. SRC did use their customer perspective screen to divide the DSM measures analyzed into three groups with respect to program marketing. The results of this analysis are shown in Table 8.1.

The first group of measures with less than a two-year payback were packaged by sector into information-only programs. The logic here being that these technologies were already highly competitive with the standard efficiency technologies in the existing marketplace. Thus, customers only needed to be educated as to the advantages and benefits of these technologies to adopt them.

The second group of measures with two to ten year paybacks were packaged by sector into energy incentive programs. The logic here is that these technologies were potentially economic options for NMGas, but that customers would need an incentive to lower the payback and overcome reluctance to purchase the measure on their own.

The third group of measures with paybacks of greater than ten years were regarded as not currently competitive in the marketplace and were, therefore, dropped from further analysis.

8.4 Fully Characterizing the Programs and Determining Market Penetration

The assumptions used to calculate the data needed for this task were developed jointly by SRC and NMGas.

Energy Savings

The annual savings estimates from the investigation were used for the residential program analysis. For all technologies the annual consumption figures were assumed to be distributed seasonally, 90 percent in the winter season and 10 percent in the summer, as the technologies analyzed are assumed to be for heating-only residential dwellings. The peak-day figures were only assumed to apply in winter.

The annual savings estimates for the commercial and industrial sectors were developed by SRC. For both the commercial and industrial space heating technologies, the entire consumption is assumed to be in the winter months. The allocation to peak days is one percent of the winter consumption. For commercial space cooling technologies, the entire consumption is assumed to be in the summer months. For industrial

Table 8.1

RESULTS OF TECHNOLOGY ANALYSIS

HIGH EFFICIENCY NATURAL GAS TECHNOLOGIES WITH LESS THAN 2 YEAR PAYBACK		
Residential Sector	Commercial Sector	Industrial Sector
Programmable Setback Thermostat	Supply Air Temperature Reset Reduce Hot Water Temperature Instantaneous Water Heater	Programmable Setback Thermostat Supply Air Temperature Reset

HIGH-EFFICIENCY NATURAL GAS TECHNOLOGIES WITH BETWEEN 2 AND 10 YEAR PAYBACK		
Residential Sector	Commercial Sector	Industrial Sector
H.E. Gas Boiler (Gas Base) H.E. Gas Furnace (Gas Base) H.E. Gas Boiler (Electric Base) H.E. Gas Furnace (Electric Base) Attic Insulation	H.E. Gas Boiler (Gas Base) H.E. Gas Furnace (Gas Base) H.E. Gas Boiler (Electric Base) Energy Management System Programmable Setback Thermostat	H.E. Gas Boiler (Gas Base) H.E. Gas Furnace (Gas Base) Gas Engine Driven Air Compressor Energy Management System

HIGH EFFICIENCY NATURAL GAS TECHNOLOGIES WITH GREATER THAN 10 YEAR PAYBACK		
Residential Sector	Commercial Sector	Industrial Sector
Wall Insulation H.E. Gas Boiler (Oil Base) H.E. Gas Furnace (Oil Base)	Ceiling Insulation H.E. Gas Boiler (Oil Base) Gas Engine Driven DX AC Chiller Gas Absorption Chiller	Gas Engine Driven DX AC Chiller Gas Absorption Chiller

space cooling technologies, the consumption is assumed to be throughout the year relative to the energy distribution of the electric space cooling load shape. There is no summer peak period.

For commercial water heating technologies, the annual consumption is assumed to be split equally between the summer and winter months. The allocation to the winter peak period is 0.82 percent of the winter consumption. No industrial water heating technologies were considered. For the industrial air compressor technology, the entire consumption is assumed to be throughout the year relative to the energy distribution of an assumed air compressor load shape.

Utility administrative costs and incentives

Utility administrative costs were estimated to include a one-time cost of \$10,000 in the first year for program development and an annual cost of \$10,000 for fixed administration/marketing expenses. All incentive payments were set at 50 percent of the incremental cost of the DSM technology.

Market penetration

The market penetration for each program was calculated internally in the COMPASS model using the gas sales profile data developed for each sector and the following assumptions:

- A five-year program duration and ten-year planning horizon were used for all programs.
- For residential gas-conservation programs only, it was assumed that five percent of the eligible market had already converted to high-efficiency (DSM) equipment. No similar assumption was made for the residential fuel-switching programs or for any of the programs in the C/I sector.

- The percentage of customers not willing to adopt the DSM technology regardless of its payback or the incentives offered was assumed to be 10 percent in the program case and 20 percent in the no-program case.
- All program impacts were calculated net of free riders.
- The diffusion function used to calculate the long-run market penetration of DSM technologies in the information-only program was adjusted to reflect a 10 percent information effect. Availability of rebates for technologies in the incentive program was assumed to result in a slightly higher information effect (15 percent rather than 10 percent) than in the information-only program.

8.4 Evaluation of the Cost-Effectiveness of the DSM Programs

In this task SRC, using the data developed above, calculated the cost-effectiveness of the program concepts. The results of this analysis are contained in Tables 8.2, 8.3, and 8.4. Remember from Table 8.1 above, some of these are information-only programs and some are incentive programs.

Cost-effectiveness was calculated from three points of view: the utility (Utility Cost test), rate impacts (RIM test), and society (Societal Test). The results of the analysis were presented as benefit/cost ratios. If the ratio is above 1.0 the program is considered cost-effective from that perspective. The utility test compares the savings in gas fuel and delivery costs (gas avoided costs) to the utility administrative and incentive costs. The rate impact test compares avoided costs to utility administrative and incentive costs plus bill savings (revenue losses). The societal test compares avoided costs plus environmental benefits to utility administrative costs plus incremental customer costs.

For fuel-switching programs, these tables show the results of "combined" analyses. That is, both gas and electric avoided costs and revenue changes were included for each test. As can be seen in the tables, these programs increase gas load and decrease electric load. Therefore, the utility test compares the reduction in electric generation, transmission and distribution costs (electric avoided costs)

**Table 8.2
BENEFIT/COST AND ENERGY IMPACT RESULTS FROM ANALYSIS
OF RESIDENTIAL DSM PROGRAM DESIGNS**

Name of Program	Program Type ¹	Benefit/Cost Results ²			Energy Impacts ³			
		Utility	Rate Impact	Societal	1994		2000	
					Dis	MWh	Dis	MWh
II E. Gas Boiler (Gas Base)	(iC)	1.38	0.36	0.78	19,389	-	227,905	-
II E. Gas Furnace (Gas Base)	(iC)	2.10	0.40	1.20	77,183	-	920,453	-
III E. Gas Boiler (Electric Base)	FS E->G	1.58	0.56	1.22	-134,072	30,648	-513,912	117,477
III E. Gas Furnace (Electric Base)	FS E->G	1.93	0.54	1.49	-117,549	35,263	-437,229	131,163
Programmable Setback Thermostat	(iC)	276.32	0.46	1.65	232,126	-	826,583	-
Attic Insulation	(iC)	0.97	0.32	0.55	225,266	-	738,677	-
Subtotal					302,343	65,911	1,807,477	248,640

1. Program Type: (iC) = Gas Conservation Program, FS E->G = Fuel Switch Program, Electricity to Natural Gas.

2. Benefit/Cost results are from utility, rate impact, and societal perspectives. B/C ratios for fuel switching programs are shown from the combined (electric and gas) utility perspective.

3. Impacts are energy savings in decatherms (Dt) and MWh in the years 1994 and 2000.

**Table 8.3
BENEFIT/COST AND ENERGY IMPACT RESULTS FROM ANALYSIS
OF COMMERCIAL DSM PROGRAM DESIGNS**

Name of Program	Program Type ¹	Benefit/Cost Results ²			Energy Impacts ³			
		Utility	Rate Impact	Societal	1994		2000	
					Dis	MWh	Dis	MWh
H.E. Gas Boiler (Gas Base)	GiC	0.76	0.31	0.52	414	-	5,677	-
H.E. Gas Furnace (Gas Base)	GiC	0.77	0.31	0.49	562	-	7,513	-
H.E. Gas Boiler (Electric Base)	FS E->G	2.16	0.71	1.91	-14,743	3,575	-68,548	16,622
Supply Air Temperature Reset	GiC	28.96	0.51	2.65	21,903	-	78,710	-
Reduce Hot Water Temperature	GiC	13.32	0.42	10.06	10,883	-	43,985	-
Instantaneous Water Heater	GiC	3.35	0.39	1.99	2,731	-	11,465	-
Energy Management System	GiC	1.46	0.38	0.83	27,477	-	113,526	-
Programmable Setback Thermostat	GiC	2.65	0.44	1.75	13,465	-	50,440	-
Subtotal					62,292	3,575	242,328	16,622

¹ Program Type: GiC = Gas Conservation Program, FS E->G = Fuel Switch Program, Electricity to Natural Gas.

² Benefit/Cost results are from utility, rate impact, and societal perspectives. B/C ratios for fuel switching programs are shown from the combined (electric and gas) utility perspective.

³ Impacts are energy savings in decatherms (Dt) and MWh in the years 1994 and 2000.

Table 8.4
BENEFIT/COST AND ENERGY IMPACT RESULTS FROM ANALYSIS
OF INDUSTRIAL DSM PROGRAM DESIGNS

Name of Program	Program Type ¹	Benefit/Cost Results ²			Energy Impacts ³			
		Utility	Rate Impact	Societal	1994		2000	
					Dts	MWh	Dts	MWh
H.E. Gas Boiler (Gas Base)	GC	0.07	0.07	0.08	24	-	275	-
H.E. Gas Furnace (Gas Base)	GC	0.03	0.03	0.03	10	-	114	-
Supply Air Temperature Reset	GC	0.40	0.24	0.39	345	-	1,202	-
Gas Engine Air Compressor	FS E->G	1.58	0.93	1.21	-1,814	188	-91,549	9,468
Programmable Switch Thermal	GC	0.20	0.15	0.20	170	-	613	-
Energy Management System	GC	0.72	0.33	0.61	867	-	3,362	-
Subtotal					-798	188	-85,983	9,468

¹ Program Type: GC = Gas Conservation Program, FS E->G = Fuel Switch Program, Electricity to Natural Gas.

² Benefit/Cost results are from utility, rate impact, and societal perspectives. B/C ratios for fuel switching programs are shown from the combined (electric and gas) utility perspective.

³ Impacts are energy savings in decatherms (Dt) and MWh in the years 1994 and 2000.

to the increase in gas fuel and delivery costs plus utility administrative and incentive costs. The rate impact test for fuel switching programs compares electric avoided costs plus gas revenue gain to an increase in gas fuel and delivery costs plus electric revenue losses, and utility administrative and incentive costs. The societal test compares electric avoided costs to the increase in gas fuel and delivery costs plus utility administrative costs and customer incentive costs.

It would have been informative for this study to also have calculated and reported the utility and rate impact test with gas-only results. The utility test with combined results shows the impact of the program on electric and gas revenue requirements together. This is appropriate for NMGas to consider since it is a combined utility, however, a separate calculation of a gas-only utility test would have indicated the impact on just the gas revenue requirements of the programs. Indeed, company personnel later calculated and considered the gas-only results and these indicated potential positive benefits to the gas utility from some fuel switching programs. These programs are being examined further for possible inclusion in the final IRP. Similarly, the rate impact test with combined results shows the impact of the program on electric and gas rates combined. A combined societal test is appropriate for fuel-switching programs.

As can be seen in the tables, all residential programs but one are cost-effective according to the combined utility test. Therefore, implementation of one or any of these five programs would decrease combined gas and electric utility revenue requirements. All programs fail the combined rate impact test. Therefore, implementation of one or any of these programs would cause combined gas and electric rates to increase. It is unclear from the results presented whether the fuel-switching programs would decrease gas rates. It is likely that they would, but these programs would definitely increase electric rates. Four of the six programs are cost-effective according to the societal test. That is, implementation of one or any of these programs will lower total energy service costs to society.

Six of the eight commercial programs pass the combined utility test. None of the programs pass the combined rate impact test, and five of the eight programs are cost-effective according to the societal test.

Only one of the industrial programs passes the combined utility test, the gas air compressor fuel-switching program. This same program is the only one that passes the societal test, and no industrial programs pass the combined rate impact test.

As discussed above, the test results that are used to determine whether a program is included in the integration analysis in Step 6 depends on the goals of the utility for its IRP. Given NMGas' goals defined in Section 4.2 the RIM test results should be used to program acceptance.

8.5 Conclusion

This section presents the lessons learned by NMGas when performing this step of their IRP process.

- **Coordinate the work between Steps 4 and 5.** The work performed for Step 5 repeated some, but not much, of the work performed in Step 4. These two steps are by nature highly interrelated, and therefore, it is recommended that they be completed by the same team of people. If this is not possible, significant interaction and communication between the two teams is essential.
- **Include at least one program for each of the largest customer segments and end uses.** The gas sale profile data developed in Step 4 indicated that process heating constitutes approximately 50 percent of industrial gas loads. Yet there was no DSM program developed to address this market. It would have been interesting to determine the impact of such a program.

Chapter 9

Step 6 : Conducting An Integrated Evaluation

9.0 Overview

The IRP analysis culminates in the integrated evaluation. This phase of the IRP process results in portfolios of options that, when combined, meet the identified resource requirements. These portfolios are evaluated and their results compared against each other. This evaluation would account for factors and evaluation criteria that are best evaluated on a plan rather than on an individual option basis. Such factors include items such as overall rate impact, year-by-year rate impacts, financial implications, public and environmental concerns, risk diversification, reliability and competitive implications.

The portfolio of alternatives for the integrated analysis phase are developed based on screening results from Chapters 7 and 8. Whereas avoided cost is the principal cost tool used in the screening phase, the integrated evaluation phase captures the interaction of many resource alternatives and the discrete size and times associated with major capacity additions.

The following sections describes the results and conclusions drawn from NMGas' integration process.

9.1 Results of The Integration Process

The traditional integrated analysis restricts itself to comparing supply-side and demand-side resource options to determine the most cost effective mix of resources to meet demand. In the case of NMGas the process would be the same, however the analysis chose no alternatives other than the current and future supply resources.²⁵ The reason for this result, as discussed in the preceding chapter, is that none of the demand-side resources was shown to pass the RIM test. This means that if adopted, any of the demand-side options analyzed

²⁵NMGas is currently examining whether there are any available, cost effective, demand-side load building programs.

would lead to increased rates. Since an original objective of the Company was minimizing the rate impacts to their customer, any program failing the RIM test would be inconsistent with this corporate objective.

There are two basic reasons for this result. First, NMGas has sufficient capacity to meet its forecasted demand for the next 10 years. Second, marginal gas supply costs are approaching historic lows (in real terms) and consequently the company's avoided costs are very low. This makes it difficult for alternative resources to be cost effective. In sum, the company's supply options were simply more cost effective than the alternative demand-side proposals considered.

9.1 Conclusions

This section presents the lessons learned by NMGas when implementing this step of their IRP process.

- **When the IRP process is reopened, if the planning and/or forecast assumptions have changed, the Company should first revisit these same demand-side options.** This conclusion was stated in an early draft of the IRP and was predicated on the fact that since these were the "best available" options at the present time they should be the first to be considered in the next round.
- **Future IRPs will build on this initial process.** In essence, the Company has benefit from this experience and the next IRP should be both easier and faster.

Chapter 10

Step 7 : Developing An IRP Strategy

10.0 Overview

An IRP strategy selects a portfolio of options that are adopted as the resource plan. The IRP strategy is generally documented in a published report and should identify :

- Anticipated resource commitments;
- Action required to secure major resources;
- Contract (supply, storage and transportation) restructuring objectives and targets;
- Aggregate targets and goals for demand side alternatives (shaving the peak, peak shifting, conservation, efficiency, load building and new market development); and
- Rate design and pricing objectives.

The degree of detail associated with each item of the strategy will differ for each gas utility depending upon the circumstances. For example, some utilities may decide to develop detailed demand-side programs as part of the IRP process. Other utilities may use the IRP to establish targets for demand-side activities and leave detailed program selection and design issues to a later stage. At that stage, program details could be developed so as to be consistent with the IRP strategy developed.

From a practical perspective, many of the planning activities will require detailed work by special departments. The IRP might then be best used to set goals and targets in each area rather than to develop detailed plans for each activity. The IRP would then serve as a basis to ensure that such goals and targets are integrated into planning and that subsequent plans in each activity are consistent with the IRP.

In the following section the experience of NMGas in developing their IRP strategy and accompanying report. The chapter closes with some general conclusions about this step in the process.

10.1 The IRP Strategy and Report

The development of an appropriate IRP requires extensive resources throughout a company. Such was the case for NMGas as all areas of planning within the company were extensively involved. These included transmission and distribution, gas supply, demand-side coordinators, customer service, marketing, rate design, forecasting, financial planning and new business planning. Therefore, the draft document produced from this process was very extensive, detailed, and included strategy for each of these business service centers.

According to the draft IRP, it was felt this IRP process, in producing these strategies, served "...four goals. First, it strives to provide an effective way to collect, manage, and disseminate information for business planning purposes. Second, it purposely to questions the ability of existing strategies to get what we [Company] want when we want it. Third, it works to get everyone pulling in the same direction. And fourth, it seeks to produce insights and recommendations for change that stem from experience, expertise, and defensible analysis."

However, in the fashion that the IRP was developed the process and resultant draft document evolved more into a business plan than what some may consider a traditional IRP. Indeed, NMGas' experience showed their gas IRP should reflect the same decision criteria, planning assumptions and resource requirements of a business plan. To that end the draft IRP Report says that "the IRP planning process will become an integral part of NMGas' business planning process." Furthermore, it says the report will be used as a physical point of reference for strategic decisions and ensuing operating plans with a planning horizon of both 0-3 years (short term) and >3 years (long term). In terms of actual business planning, the draft report provided recommendations on gas supply planning, rates and new business opportunities.

10.2 Conclusions

These are the general conclusions that could be drawn from NMGas' experience in this step of the process.

- **The IRP Report provided NMGas a multi-department, comprehensive, planning document.** The interdepartmental relationships, knowledge of other departments and general experiences gained through the process could provide benefits to the company's overall planning efforts.
- **There was difficulty in finding available time for the resources required to complete the task.** *This is a critical decision factor that NMGas had to address and is primarily a resource allocation issue.* One means of overcoming this was for the project coordinator to specifically schedule meetings with the appropriate individuals in order to get their inputs. This again highlights the need for management to establish appropriate priorities if the desire is for the IRP to be done in the most expedient manner.
- **Once resources were committed the process took approximately 10-12 months of actual time to complete.** The revised schedule called for completion of the report by January, 1994. As of September 15, 1994, the third draft IRP Report is out for comments. An actual final report is expected to be ready by the fourth quarter of 1994, which is about 9 months behind schedule. However, according to company personnel, once the process was staffed and the IRP given priority, the total time involved in the whole IRP process was approximately 10-12 weeks.

Chapter 11

Summary

11.0 Overview

This chapter presents a summary review of the conclusions documented within this report regarding the experiences and lessons learned by NMGas as they developed their initial IRP. In the following section some basic insights are outlined that were formulated primarily from contemporaneous project documentation and notes. In an effort to add additional perspective to this review a number of individual interviews were conducted with Company personnel involved in the project. Their insights, discussed in Section 11.2, provides guidance as to what might be some future considerations in regards to a natural gas IRP. In Section 11.3 the most significant overall lessons learned by NMGas are discussed.

11.1 Basic Insights

These basic insights were the major issues, circumstances, or discoveries which were realized as NMGas progressed through the development of their IRP. They were highlighted at the end of the preceding chapters, however here they are segregated into two categories. The first category lists the issues and their related steps in the process on which NMGas had to make decisions that were crucial to the continuation and or development of the IRP. The second category lists those insights and observations that could provide general guidance to other gas IRP efforts.

Critical Decision Points

Step 1

- **The objectives of the IRP should be consistent with corporate goals.** *This was a critical decision for NMGas since it helped focus efforts towards common objectives.* NMGas concluded that several objectives, consistent with their corporate goals, should guide their IRP process. These included minimizing the cost of gas services to customers, maximizing

shareholder value, satisfying environmental requirements, developing a flexible plan and not adversely affecting rates. The latter objective indicated that the appropriate IRP economic evaluation criteria for NMGas at this time would be the Rate Impact Measure test.

Step 2

- **Careful attention to the planning assumptions and policy guidelines is essential.** *These planning assumptions were critical decisions for NMGas since they defined the study parameters and guidelines.* These assumptions eventually determine both the bounds and the outcome of the IRP process.

Step 3

- **The major conclusion of this step indicated that NMGas would have sufficient supply resources and related transmission capacity beyond that necessary to meet projected firm demand.** *This was a critical conclusion that affects how a company's IRP proceeds.* For example, as opposed to a load reducing demand-side program being used as a substitute for projected new supply resources, those demand-side programs are now being considered as "replacement" energy for supply resources already committed. To the extent those projected new resources might be more expensive than resources already obtained and/or if those current supply resources have firm contracts this can affect the economic evaluations.
- **It was necessary to establish criteria related to resource options.** *These were critical decisions because they focused NMGas' search on resources that met the Company's predefined criteria in regards to comparability of service and reliability.*

Step 4

- **Make sure the economic screening criteria match the goals of the IRP.** *It is critical to coordinate the objectives of the company with the objectives of the IRP and subsequently the economic screening criteria.* To that end, as established in the initial step of the process, the appropriate screening criteria for NMGas was the Rate Impact Measure test.

Step 7

- There was difficulty in finding available time for the resources required to complete the task. *This is a critical decision that NMGas had to address and is primarily a resource allocation issue.* This highlights the need for management to define appropriate priorities if the IRP is to be done in the most expedient manner.

General Guiding Principles

- The project approach was similar to that described in the NARUC Gas IRP Primer.
- A multi-function project team was established to develop the IRP. This was a small team composed of four to five members with one overall IRP leader dedicated to the project. This proved beneficial because the IRP process crosses a number of functional areas within the Company therefore this collaborative effort was a good means of facilitating the IRP process.
- There was a need for the team members, as well as senior management, to be "committed" to the project. Without this senior level commitment to the process and with an appropriate priority status the project could be frequently delayed. Furthermore, the project team leader found it critical for task assignments to be communicated precisely to team members. In other words, simply because the team leader understood the requirements of the IRP process did not necessarily mean other team members were so knowledgeable and/or had the same understanding.
- Planning assumptions are subject to revisions. This is due to the changing nature of the gas industry and related competitive pressures. As one company individual put it, "you can't make these planning assumptions in a vacuum and put them in a box, because they can change quite rapidly."
- Planning assumptions and policy guidelines must be tailored to the requirements of the gas industry and to each company's strategic objectives. It is critical to emphasize that for individual LDCs there

will be assumptions related to their specific needs, goals and their service areas that must be factored in to any planning scenario used in developing the IRP.

- **Gas resource planning is likely to focus on multiple demands.** This can include peak day, peak season, etc. Unlike electric utilities where the ability to meet peak demand generally enables all energy requirements to be met, gas supply capability often has volumetric as well as capacity limits. Hence, it will not be unusual to focus on multiple demands for gas utilities in setting resource requirements.
- **Gas utility planning criteria for individual gas utilities may differ more than planning criteria for electric utilities.** For example, there is likely to be more disparity in reserve margins among gas utilities. These differences result from market and supply differences which in effect means that gas utilities are likely to be less homogeneous than electric utilities and to have, for good reason, reliability criteria that differ.
- **A theoretically sound avoided cost methodology was defined for gas utilities that can be used in the economic evaluations of resource options.**
- **Start with a load shape screening process in Step 4.** The screening effort performed in this step could have been shortened and focused by beginning with a simple load shape screening analysis.
- **Coordinate the work between Steps 4 and 5.** These two steps are by nature highly interrelated, and therefore, it is recommended that they be completed by the same team of people. If this is not possible, significant interaction and communication between the two teams is essential.
- **Once resources were committed the process took approximately 10-12 months of actual time to complete.** The revised schedule called for completion of the report by January, 1994. As of September 15, 1994, the third draft IRP Report is out for comments. An actual final report is expected to be ready by the fourth quarter of 1994, which is about 9 months behind schedule. However, according to company personnel, once the process was staffed and the IRP given priority, the total time involved in the whole IRP process was approximately 10-12 weeks.

11.2 Future Direction

In trying to assess the benefits and add additional insights from the experiences of NMGas a number of interviews were held with personnel who participated in this project. They were specifically asked about their perception of the pitfalls, problems, and benefits, associated with the process as well as whether or not the IRP process should be repeated. The following is a summary of their observations.

- **Future IRPs will build on this initial process.** In essence, the Company has benefited from this experience and the next IRP should be both easier and faster.
- **There was consensus among the team members that the process was worthwhile and should continue.** However, there was some concern about how often to do this.
- **The IRP should be a "living" document with periodic revisions coupled with an overall review every 2-3 years.** In essence, the thought here is related to the rapidity with which the industry is changing and the idea that this process should be more "real time."
- **This project evolved into more of a business plan than what some might consider a traditional IRP.** This presented benefits as well as problems. Beneficial was the overall comprehensive planning effort that evolved and the subsequent enthusiasm for the final product's thoroughness and depth. Many felt the draft document was a comprehensive repository of all the Company's business plans, forecasts, problems and opportunities.
- **When the IRP process is reopened, to the extent prices and/or planning assumptions have changed, the Company should first revisit these same demand-side options.** This conclusion was also stated in an early draft of the IRP and was predicated on the fact that since these were the "best available" options at the present time then they should be the first to be considered in the next round.

- **Consideration should be given as to how extensive future avoided cost evaluations need to be. While an avoided cost methodology was developed, on initial analysis it might prove simple and effective to review options based on a simple gas price projection.**
- **The process from start to finish on this initial IRP, including the utilization of outside experts, took a total time commitment of 10-12 months. It is felt the lessons learned here will greatly reduce this time. It is believed that future IRPs will benefit from this experience and the time could be cut to four to six months. However, again, this depends on the priority given to personnel assigned to the project.**

11.3 The Most Significant Lessons Learned

In discussions with company personnel several key issues kept rising to the top as significant lessons learned in this process. The issues embodied in these lessons should be the initial focus of any future IRP.

- **The objectives of the IRP should be consistent with corporate goals in order to provide guidance as to the exact types of demand-side programs the company should pursue.**
- **NMGas' strategic assessment went beyond the traditional supply/demand scope of IRP. A separate analysis was done for each of the functional areas below:**
 - **Transmission and distribution,**
 - **Gas supply and demand-side management,**
 - **Finance and rates,**
 - **Marketing and customer service,**
 - **Business planning and development.**

It is felt by NMGas that future IRPs, to be of value, should be incorporated into and be a part of the overall business planning process.

- **There is great concern about the distribution of any final product and whether it becomes public. For example, the prospect of a competitor getting such a thorough "look" at NMGas and its future plans is a serious concern to management and could limit their response to future IRPs involvement.**
- **While those who worked on the project felt the IRP process should continue, as one project participant said "There remains to be specifically defined the bottom line benefits to the Company from the IRP process that are not captured in our traditional business planning activities. These need to be communicated to senior management in order to garner their support for continuing this activity."**

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Appendix I

This appendix addresses some of the demand-side management (DSM) issues explored by NMGas in its IRP process. This appendix has five sections. We begin with a definition of DSM and point out that what is often referred to as DSM is only one subset of this utility option. We next discuss how a utility would choose what DSM to offer depending on the utility's IRP goals, and then introduce a new DSM selection criterion that corrects the errors of omission in certain of the standard criteria (tests). We then discuss the DSM selection criteria appropriate for NMGas in its IRP and what that may mean in terms of their DSM offerings. And finally, we present the relationship between DSM and rates and the importance of them being developed consistently.

What is DSM?

The Electric Power Research Institute (EPRI) coined the term demand-side management in its August 1984 publication *Demand-Side Management: Volume 1 - Overview of Key Issues* (EPRI EA/EM-3597). In that document, EPRI defines DSM as:

Demand-side management is the planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape—i.e., changes in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of demand-side management include: load management, new uses, strategic conservation, electrification, customer generation, and adjustment in market share.

The document goes on to define six "load shape objectives" for DSM: strategic conservation, peak clipping, valley filling, load shifting, strategic load growth, and a flexible load shape. These load shape objectives clearly illustrated that the main purpose of DSM was to allow utilities to no longer have to take their customers' demand as fixed. Customer demand could be manipulated to benefit the utility, and its customers, as well as its shareholders.

In the time since this document was published, a variety of forces (mostly from regulators) have intervened to reduce people's perception of DSM to only those utility activities that encourage customers to reduce their energy use.

As utility markets become more competitive this narrow view of DSM unfortunately becoming damaging to the energy industry. Given present conditions, DSM activities that reduce energy use also tend to increase rates. Since rates are important under competition, many have decided that DSM has no place in energy's future. However, without DSM—i.e., without any activities that change customers' demand for energy—the industry is limited to being a commodity industry—sellers and buyers of kilowatts, kilowatt-hours, and therms.

The term DSM is unfortunate. It does not reveal that DSM as it was originally defined is simply good marketing—the packaging, pricing, promotion, and delivery of a successful product in order to maximize financial return. Without marketing we simply have

therms. With marketing we have the potential for innovation, financial gain, and customer service.

What Types of DSM Are Appropriate For a Particular Utility?

If we take a step back from the traditional concepts of the regulated utility industry and look at utilities as businesses it becomes easier to determine what types of DSM are appropriate. There are various business strategies open to utilities, and each of these strategies lends itself to a different perspective on DSM. For each business strategy there is a consistent set of planning criteria, including the selection criterion for DSM.

In its most basic form a utility can position itself either as a commodity supplier, or as a value-added energy or energy service supplier. A commodity supplier is only concerned with delivering kilowatts, kilowatt-hours or therms to the customer at the lowest cost. A value-added energy or energy service supplier is concerned with providing the most value to its customers relating to energy. Value is maximized both by increasing the worth of the energy service to the customer and by reducing its cost. Products offered by a value-added energy or energy service company (hereafter simply referred to as an energy service company) can range from "stripped-down" electric or gas service to the utility contracting to directly provide lighting and HVAC services for specific buildings.

A commodity company's goal of low cost energy can either be focused at rates (lowest cost per unit of energy) or bills (lowest cost per customer). A company focused on lowest rates will only implement DSM that reduced rates. This company's DSM selection criterion would then be the Ratepayer Impact Measure (RIM) test¹. A company focused on lowest bills will only implement DSM that reduces revenue requirements, and thus, bills. This utility would use the Utility Cost (UC) test as its selection criterion.

An energy service company's goal of maximum value (worth minus costs) can be either defined as maximum value across all ratepayers or to society as a whole. If a company's business strategy implies a goal of maximum value to all ratepayers, it will only implement DSM that passes the Value test. (The Total Resource Cost (TRC) test is the standard practice test that comes the closest to the Value test, but it is seriously biased with regard to a goal of value maximization, or even with regard to a goal of the lowest cost of energy services. These biases and their correction by the Value test are discussed in the next section.) If a company's goal is value maximization to society as a whole it will only implement DSM that passes the Societal Value test. (Again, the Societal test is the standard practice test that comes the closest to the Societal Value test, but is biased.)

Therefore, DSM is not dead. Instead, the type of DSM a utility will pursue will depend strongly on the business strategy the company adopts in response to competition.

Three additional points should be made here for perspective. First, energy efficiency is often thought to be equivalent to reducing total energy use. This is not always the case. Energy efficiency has to do with the efficient use of energy—i.e., lowering the amount of energy used per unit of output or per unit of an energy service. But if the energy efficiency is also economic, the cost per unit of the energy service has just be lowered. If

customers respond to the lower cost of the energy service with an increase in their purchase of the energy service—e.g., respond to the lower cost of heating caused by an economically energy efficient furnace by raising their thermostat setting—total energy use has not gone down as much as expected and may have even gone up. A more extreme case is an economic development program where energy efficiency so lowers the cost of production for a manufacturing company that it can better compete in its market and doubles production.

It may be that the belief that energy efficiency equates to less total energy use is the result of the biased results given by the TRC test discussed in the next section. It is interesting to note, however, that the only test that implies a reduction in total energy use through DSM is the UC test.

The second point is that many utilities have indicated that their response to competition will be to return to being commodity companies. This has been largely precipitated by customers' demands for low rates. But even though any customer will say that low rates are important, the question remains as to whether kilowatt-hours and therms are all they really want.

And finally, there are advantages and disadvantages to either market position—commodity or energy service supplier. Commodity suppliers do not have to worry about how their customers are using the energy. Energy efficiency is not a concern. On the other hand, a commodity supplier has to be sure that its generation and supply resources are cheaper than its neighbors. Profit margins are thin in the commodity business due to the lack of many remaining efficiencies.

Energy service companies will have to know a lot about their customers. Resource and production selection will be complicated by such nebulous concepts as customer wants, needs and perceptions. On the other hand, there is a huge potential for profit in energy services. One indication of this the amount of energy efficiency still available in the market.

Introduction to the Value Test

If a utility decides to position itself as a provider of energy services, its success will depend on its ability to provide value to its customers. Utilities can increase value to customers either through lowering the cost of an energy service or by increasing the worth customers receive from it. It then becomes obvious that this utility would want to offer only those DSM activities that do one or both of these things.

In order to remain financially sound, a company also has to be able to recover its costs. Utilities have been in the position of being granted cost recovery for certain commission-approved DSM through rate increases to all ratepayers. In this case, the cost of the DSM program to its recipient can be lower than its cost to the utility because the utility will make up the difference from other ratepayers. However, this practice of charging other ratepayers for DSM offered to some may not continue. In this case, a utility will only

offer DSM activities to those customers that value them more than their cost, and at a price that is above the utility's cost.

The Value test was developed in response to problems with the DSM selection criterion that was being used for the goal of lowering the cost of energy services—the Total Resource Cost (TRC) test. The Value test corrects the errors of omission in the TRC test by adding in the benefit and cost components that have been missing. These missing benefit and cost components have caused the results of the TRC test to be biased seriously skewing the industry's perspective of desirable DSM. In brief, the missing benefit and cost components are:²

- the benefit to customers of using more of an energy service;
- the full benefit to all ratepayers of the rate reduction caused by a DSM activity—or alternately, the full cost of a DSM-induced rate increase;
- the full costs to customers of adopting DSM measures; and
- the benefit of an increase in the quality of the energy service—or cost of a loss in quality.

The Value test was developed based on the economic principles of efficiency, and thus, is theoretically sound. However, in delving into the theoretical basis for the Value test, the more practical nature of the test often gets lost. The test simply says two things that are common sense—and good business sense. First, if you are going to offer a service to one group of your customers that negatively impacts the rest of your customers, you better make sure that the benefits participants receive outweigh the cost to the rest of your customers, or on net you are making everyone worse off. And you want to make sure that all your customers have access to these services so that each has at least the option of being better off. Alternately, you charge enough for the services to participants so that there is no negative impact on your other customers. Second, if offering a service to one group of customers lowers costs to all customers, it is probably a good thing to do.

When considered in this form, the Value test is simple, and it makes some important points that can no longer be ignored, especially as competition grows. The Value test specifically aids utilities facing competition in at least three ways. First, the test ensures that value to customers is increased. Second, it focuses utility efforts on specific customer concerns (by acknowledging DSM's true costs to customers), thus, showing utility responsiveness to customer needs. And finally, stepping away from the somewhat arbitrary limits of the TRC test to the above definition of the Value test can open a utility's "eyes" to a wider range of business opportunities—i.e., conservation is no longer the only option.

What Type of DSM is Appropriate for NMGas Given Its Goals?

Step 1 of the integrated resource planning (IRP) process is to define corporate objectives in order that the IRP process helps meet those goals. Through Step 1 of the IRP process (Chapter 4) NMGas decided that the objective of their integrated resource planning process was to develop a resource acquisition strategy that after considering all demand and supply options,

- minimized the cost of gas services to customers while maintaining required levels of supply reliability
- maximizes value to shareholders and customers;
- does not adversely affect rates;
- satisfied environmental requirements; and
- is sufficiently flexible so that it can be altered to accommodate the rapidly changing competitive markets in which NMGas will have to operate.

Within NMGas' IRP process this set of objectives was ultimately collapsed into an economic screening criterion for DSM of the Ratepayer Impact Measure (RIM) test. That is, if a DSM program caused gas rates to increase more than the supply-side alternative, it was eliminated from consideration in the final IRP.

Given the above discussion on the Value test, there is an alternative set of resource selection criteria that could have been considered. The Value test measures whether a DSM program reduces the cost of gas services to customers, and whether customer value has increased. Therefore, programs that pass the Value test will help meet these two NMGas objectives. Programs that pass the Value test can either increase or decrease rates, and rate increases are minimized for conservation-type programs because market barrier costs are acknowledged. Therefore, a package of DSM could be created containing both rate increasing and rate decreasing programs with a net rate impact of zero -- thus, meeting the objective of not adversely affecting rates. This would allow NMGas to offer a package of programs that increases value to customers while not adversely affecting rates. This package of programs would be more diverse and offer customers more value than a package of programs limited to only those that pass the RIM test.

Value to shareholders and plan flexibility need to be measured using other means, and the costs or benefits of environmental externalities can be included in the Value test analysis, if desired.

The Relationship Between DSM and Rates

Traditional DSM analysis has taken utility rate design and rate levels as a given. This is contrary to good business planning. The pricing of a product should not be removed from the rest of its marketing, nor from the marketing of a company's other products. DSM planning and rate design cannot operate in isolation of each other and be successful.

Rates affect DSM selection criteria through the prospect of losses or gains in revenue depending on whether the DSM program reduces or increases a customer's demand for gas. Reductions or increases in gas use also reduce or increase the utility's cost of supplying gas. If a DSM program reduces a particular component of a customer's gas service—say, summer therms—and that customer pays more for that component than it costs the utility to supply it, the utility loses money by offering that DSM activity. Alternately, if a DSM program increases that particular component's use by the customer, the utility gains. Yet reductions in off-season gas use may be of value to certain customers, and be a service that the utility wants to offer its customers.

The relationship between rates—especially the rate charged for each component of gas service (the rate structure)—and the DSM activities are important. Since DSM activities by definition change customers' demand for various components of traditional gas service, the utility needs to strike a careful balance between the prices charged for the various "products" offered. For example, if it is difficult for the utility to charge enough for winter peak-day use to cover the provision of that service, then it would be a good idea to design and offer DSM to reduce peak day use.

In general, it makes sense to price as close to cost as possible for the various components of traditional gas service, and then consider promoting DSM activities that increase the use of components where the price exceeds costs by a greater amount, and that reduce the use of components only where the price is less than or very close to cost.

¹ This appendix assumes the reader is familiar with the standard practice tests. If not, please refer to the California Public Utilities Commission (CPUC) and California Energy Commission (CEC), *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs*, (Sacramento, Calif.: CPUC and CEC, December 1987). In brief, the Ratepayer Impact Measure (RIM) test is the test of whether a DSM program will lower rates; the Utility Cost (UC) test is the test of whether the program will reduce revenue requirements or average bills; the Total Resource Cost (TRC) test is—of the standard practice tests—the test of whether the program will reduce the total cost of energy services across all ratepayers; and the Societal test is—again, of the standard practice tests—the test of whether the program will reduce the total cost of energy services for society as a whole. But as shown in this appendix the TRC and Societal test are seriously biased in their measure of energy service costs.

² For more detail on the derivation and implications of the Value test, see *The Value Test: Its Context, Description, Calculation, and Implications* prepared for the California Energy Commission by Patricia Herman of Barakat & Chamberlin, May, 1994, and "Summary of Main Points and Answers to Questions Received at the May 12, 1994, Workshop on the Value Test and Related Policy Issues" prepared for the New York Gas Group by Patricia Herman of Barakat & Chamberlin and Steve Braithwait of Christensen Associates, July, 1994.